CENTRAL CALIFORNIA PROVINCE

by Catherine A. Dunkel, Drew Mayerson, and Kenneth A. Piper

Location

The Central California province is located offshore California from the Mendocino fracture zone near Cape Mendocino (on the north) to the "Amberjack high" (a northeast-trending subsurface structural trend) near Point Conception (on the south). This Federal offshore assessment province is bounded on the east by the 3-mile line and on the west by the base of the continental slope (fig. 33).

The province includes five Tertiary basins that lie primarily on the continental shelf: Point Arena, Bodega, Año Nuevo, Partington, and Santa Maria. The Partington and Santa Maria basins have been combined as a single assessment area, due to the interbasinal (continuous) extent of Neogene strata. Two late Tertiary, continental slope basins (Cordell and Santa Lucia) are also encompassed by the province; however, sufficient petroleum geologic data are lacking in these basins and they have not been evaluated in this assessment.

Geologic Setting

The central California continental margin is characterized by a predominant northwest-southeast structural grain that defines the orientation of basin axes, faults, folds, and paleohighs. Offshore and onshore data along the margin suggest that a number of the basins along the modern continental shelf and slope formed in early to middle Tertiary time by extension (Blake and others, 1978), and that by middle Tertiary time, the tectonic style along the margin was predominantly right-lateral translation (transpression to transtension) (McCulloch, 1987b). Most of the basins are bounded on the east by faults associated with the right-lateral San Andreas fault system, although the extent and timing of strike-slip displacement on individual faults are uncertain. The nature of basement rocks and the distribution of Cretaceous and Paleogene strata vary considerably across the province; however, thick sequences of Neogene strata are widely distributed over each of the basins, and these strata compose the bulk of the stratigraphic fill. Although the basins have somewhat similar stratigraphic and structural characteristics, each basin has a distinct history of development, subsidence, deposition, and deformation. A detailed discussion of the geologic framework and evolution of the central California margin is presented by McCulloch (1987b, 1989).

Significance of Siliceous Rocks

Strata in the assessed basins of the Central California province include thick sections of Neogene siliceous rocks, some of which have been identified as or are lithologically and temporally similar to rocks of the Miocene Monterey Formation. The Monterey Formation is an unusual and important rock unit in several well-explored California coastal basins (e.g., Santa Maria and Santa Barbara-Ventura basins) because it contains both source rocks and reservoir rocks for petroleum. Although there is limited direct information regarding Neogene siliceous rocks in the less-explored basins of the Central California province (e.g., Point Arena, Bodega, Año Nuevo, and Partington basins), they are expected to have lithologic characteristics similar to those in the well-explored basins and to be equally significant as a petroleum source and reservoir.

Neogene siliceous rocks in the California coastal basins typically consist of a series of siliceous facies that record the progressive diagenesis[5] of silica. The facies include (1) opal-A (biogenic opaline silica with amorphous crystalline structure), (2) opal-CT (diagenetic opaline silica with cristobalite-tridymite crystalline structure), and (3) diagenetic quartz. The diagenesis of opal-A to opal-CT and of opal-CT to quartz is accompanied by a successive reduction of matrix porosity and an increase in the density of the rock. Sufficient density contrasts across these silica diagenetic boundaries may be marked by prominent reflecting horizons on seismic-reflection profiles and/or increased density measurements on well logs. The dense and brittle rocks containing diagenetic silica (opal-CT and quartz) are susceptible to fracturing and may have secondary porosity in the form of fractures along which petroleum may migrate and accumulate. Recognition of the stratigraphic position of the diagenetic boundaries may, therefore, provide a means to predict the characteristics and relative prospectiveness of reservoir rocks.

Studies of the organic geochemistry and thermal maturity of Monterey Formation rocks in the Santa Maria and Santa Barbara-Ventura basins indicate

[5] Diagenesis is the alteration of sediment after its initial deposition by processes (e.g., compaction, cementation, and mineralogic replacement) that occur under conditions of pressure and temperature.

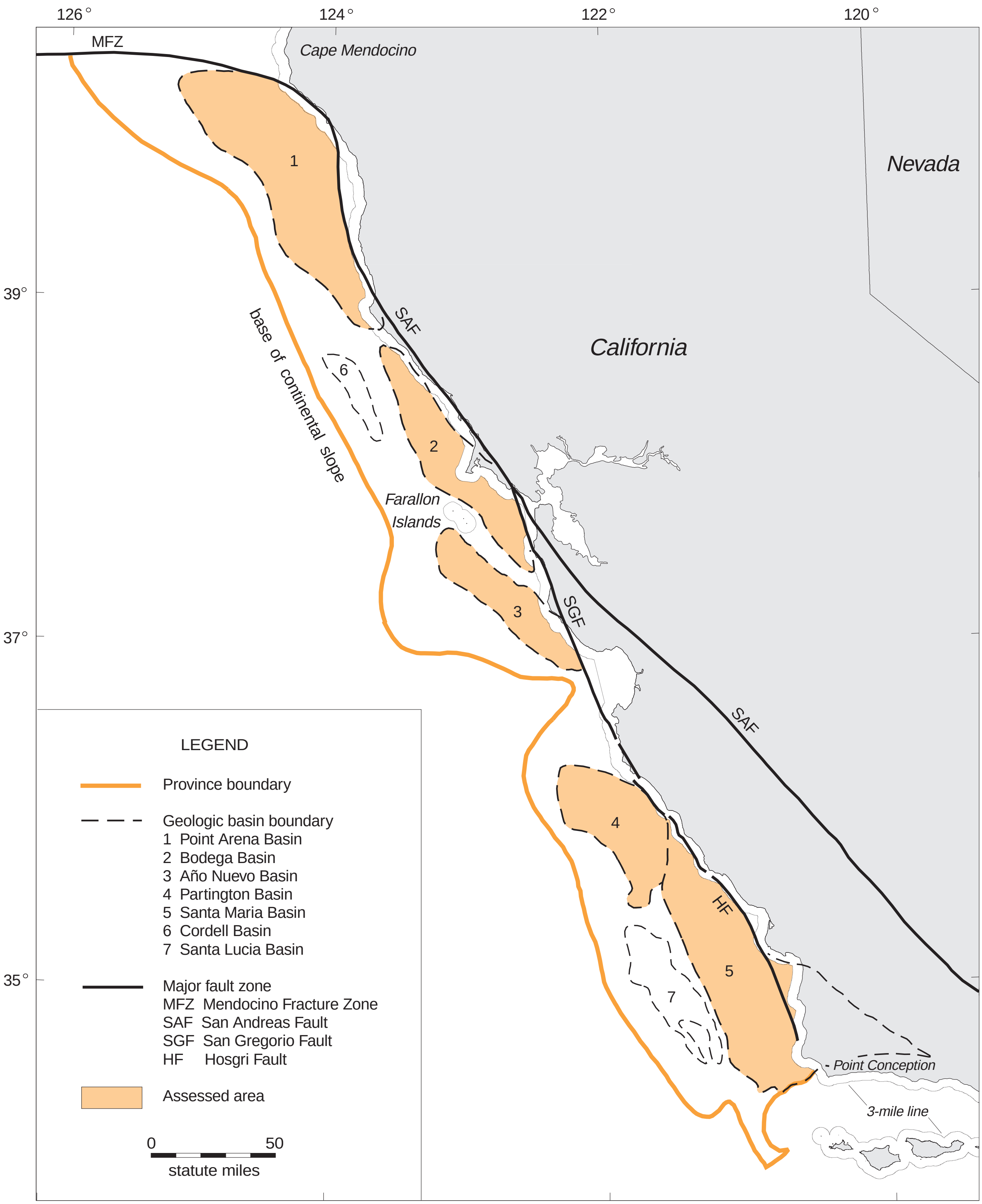

Figure 33. *Map of the Central California province showing geologic basins and assessed areas.*

that petroleum generation has occurred at low levels of organic metamorphism (Isaacs and Petersen, 1987; Petersen and Hickey, 1987) and suggest that generation has occurred at lower temperatures (i.e., less than 100 °C) and shallower depths than predicted by conventional organic metamorphic models (Isaacs and others, 1983). Although the specific temperature for oil generation in Monterey rocks is unknown, the thermal threshold appears to coincide with the temperature at which opal-CT is diagenetically transformed to quartz (i.e., approximately 80 °C) (Surdam and Stanley, 1981; Keller and Isaacs, 1985). The apparent thermal coincidence of the generation of petroleum and diagenesis of opal-CT to quartz is significant because it provides a basis for the estimation of paleotemperature and the depth and location of petroleum generation in the absence of geothermal, geochemical, and thermal maturity data.

Mineralogic analyses of Neogene siliceous rock samples from nine offshore wells in the Point Arena, Bodega, Año Nuevo, and Santa Maria basins indicate that diagenesis of opal-CT to quartz has occurred in all of the wells; the stratigraphic position of this diagenetic boundary has been correlated with a “diagenetic reflector” on seismic-reflection profiles that can be traced through part or much of the offshore areas of the basins (Mayerson and others, 1995). The analyses further indicate that petroleum generation may have occurred at relatively shallow depths (i.e., as shallow as 3,000 to 5,000 feet below the seafloor) and that generative source rocks and fractured reservoir rocks may exist over large areas of the basins. Recognition of the location and petroleum geologic significance of the silica diagenetic boundaries and facies in basins of the Central California province is considered to be a notable improvement from past assessments.

Basis for Play Definition

Petroleum geologic plays within each of the assessed basins have been defined on the basis of reservoir rock stratigraphy and occur in one of three reservoir groups: (1) Paleogene to lower Neogene clastic reservoirs, (2) Neogene fractured siliceous reservoirs, and (3) upper Neogene clastic reservoirs. Fractured siliceous strata were originally subdivided into three subplays; two of these were defined on the basis of silica diagenetic grade to distinguish between moderately fractured, opal-phase reservoirs and highly fractured, quartz-phase reservoirs in conventional structural traps. These subplays were eventually combined into a single play for practicality of statistical analysis. Additionally, a highly speculative subplay of quartz-phase stratigraphic traps sealed by low permeability above the opal-CT-quartz diagenetic boundary was defined but not assessed.

Exploration and Discovery Status

Several offshore oil fields have been discovered in the Santa Maria basin, where production is derived primarily from Monterey reservoirs. Although the Point Arena, Bodega, and Año Nuevo basins have been only sparsely explored, the limited exploration data suggest that significant hydrocarbon potential exists within these basins as well.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of the total volume of undiscovered conventionally recoverable resources in the province have been developed by statistically aggregating the constituent assessment area estimates. As a result of this assessment, the total volume of undiscovered conventionally recoverable resources in the Central California province is estimated to be 4.95 Bbbl of oil and 5.23 Tcf of associated gas (mean estimates). The low, mean, and high estimates of resources in the province are listed in table 11 and illustrated in figure 34.

Economically Recoverable Resources

Estimates of the total volume of undiscovered conventionally recoverable resources in the province that may be economically recoverable under various economic scenarios have been developed by statistically aggregating the constituent assessment area estimates. As a result of this assessment, 2.59 Bbbl of oil and 2.77 Tcf of associated gas are estimated to be economically recoverable from the Central California province under economic conditions existing as of this assessment (i.e., the $18-per-barrel economic scenario) (table 12). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions (fig. 35).

Total Resource Endowment

As of this assessment, cumulative production from the province was 118 MMbbl of oil and 43 Bcf of gas; remaining reserves were estimated to be 667 MMbbl of oil and 659 Bcf of gas. These discovered resources and the aforementioned undiscovered conventionally recoverable resources collectively compose the province’s estimated total resource endowment of 5.74 Bbbl of oil and 5.93 Tcf of gas (table 13).

Table 11. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Central California province as of January 1, 1995, by assessment area. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

Assessment Area	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Point Arena Basin	1.50	2.03	2.66	1.45	2.14	3.01	1.77	2.41	3.18
Bodega Basin	0.97	1.42	1.98	1.00	1.57	2.30	1.16	1.70	2.37
Año Nuevo Basin	0.49	0.72	1.01	0.49	0.78	1.16	0.58	0.86	1.21
Santa Maria-Partington Basin	0.68	0.78	0.89	0.60	0.74	0.90	0.79	0.91	1.05
Total Province	*4.17*	*4.95*	*5.82*	*4.21*	*5.23*	*6.39*	*4.94*	*5.88*	*6.93*

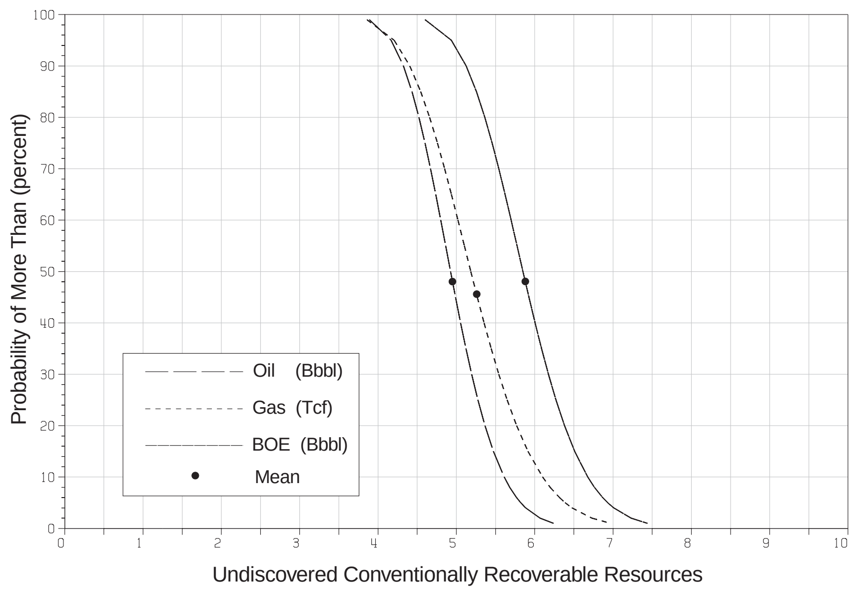

Figure 34. *Cumulative probability plot of estimated undiscovered conventionally recoverable resources of the Central California province.*

Table 12. *Estimates of undiscovered economically recoverable oil and gas resources in the Central California province as of January 1, 1995 for three economic scenarios, by assessment area. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $25-per-barrel scenario is based on prices of $25 per bbl of oil and $2.94 per Mcf of gas; the $50-per-barrel scenario is based on prices of $50 per barrel of oil and $5.87 per Mcf of gas. Some total values may not equal the sum of the component values due to independent rounding.*

Assessment Area	$18-per-barrel Scenario			$25-per-barrel Scenario			$50-per-barrel Scenario		
	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Point Arena Basin	0.90	0.95	1.06	1.21	1.27	1.43	1.58	1.66	1.87
Bodega Basin	1.03	1.13	1.23	1.14	1.26	1.37	1.27	1.41	1.52
Año Nuevo Basin	0.48	0.51	0.57	0.55	0.59	0.65	0.63	0.68	0.75
Santa Maria-Partington Basin	0.19	0.18	0.22	0.28	0.26	0.32	0.50	0.47	0.58
Total Province	*2.59*	*2.77*	*3.08*	*3.17*	*3.38*	*3.77*	*3.98*	*4.22*	*4.73*

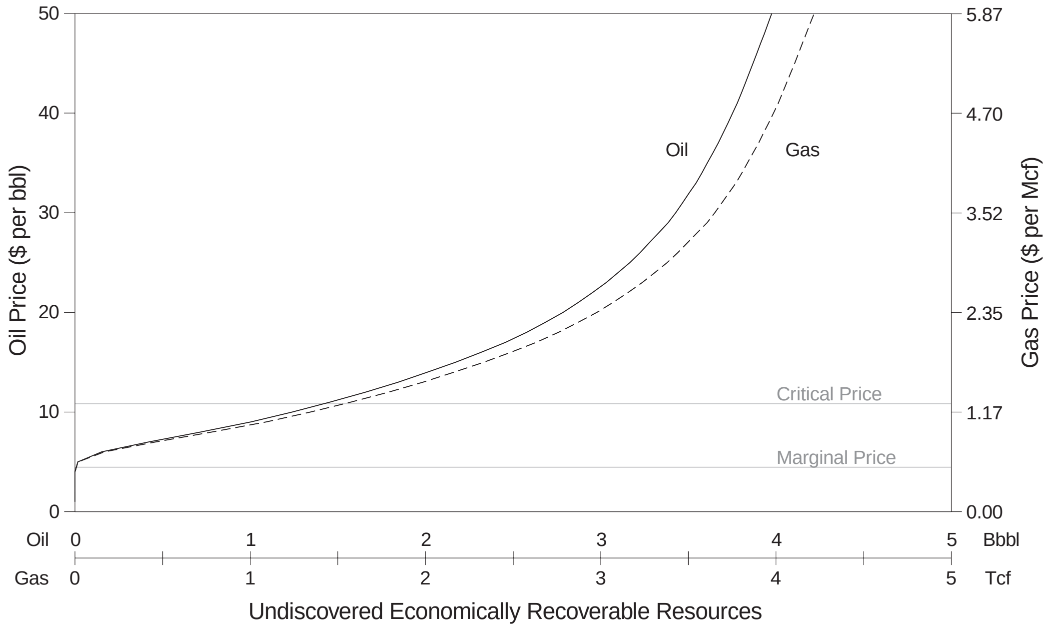

Figure 35. *Price-supply plot of estimated undiscovered economically recoverable resources of the Central California province.*

Table 13. *Estimates of the total endowment of oil and gas resources in the Central California province, by assessment area. Estimates of discovered resources (including cumulative production and remaining reserves) and undiscovered resources are as of January 1, 1995. Estimates of undiscovered conventionally recoverable resources are risked mean values. Some total values may not equal the sum of the component values due to independent rounding.*

Assessment Area	Discovered Resources (Reserves)						Undiscovered Conventionally Recoverable Resources			Total Resource Endowment		
	Cumulative Production			Remaining Reserves								
	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Point Arena Basin	0	0	0	0	0	0	2.03	2.14	2.41	2.03	2.14	2.41
Bodega Basin	0	0	0	0	0	0	1.42	1.57	1.70	1.42	1.57	1.70
Año Nuevo Basin	0	0	0	0	0	0	0.72	0.78	0.86	0.72	0.78	0.86
Santa Maria-Partington Basin	0.12	0.04	0.13	0.67	0.66	0.78	0.78	0.74	0.91	1.57	1.44	1.82
Total Province	*0.12*	*0.04*	*0.13*	*0.67*	*0.66*	*0.78*	*4.95*	*5.23*	*5.88*	*5.74*	*5.93*	*6.79*

POINT ARENA BASIN

by Kenneth A. Piper

LOCATION

The Point Arena basin is the northernmost basin in the Central California province (fig. 33). It extends from Punta Gorda to south of Point Arena, California, a distance of about 100 miles; it is about 30 miles wide and encompasses an area of about 3,000 square miles (fig. 36). A small part of the basin extends into State waters and onshore at Point Delgada and Point Arena.

The Point Arena Basin assessment area comprises only the Federal offshore portion of the basin (i.e., seaward of the 3-mile line). Water depth in the assessment area ranges from about 200 feet at the 3-mile line to about 5,000 feet along the western margin.

GEOLOGIC SETTING

Basement rocks are unknown. In the northwestern part of the basin, near the Mendocino fracture zone, deep-sea drill site 173 bottomed in andesite at 1,050 feet below the seafloor and stratigraphically beneath upper Oligocene to lower Miocene sediments (Kulm, von Huene, and others, 1973). The rock most likely originated as a subaqueous breccia flow and is compositionally similar to Cascade Range volcanics (MacLeod and Pratt, 1973). Reworked Cretaceous microfossils from site 173 cores and a dredge sample from south of the drill site (Silver and others, 1971) suggest Franciscan Complex underlies at least the western part of the basin

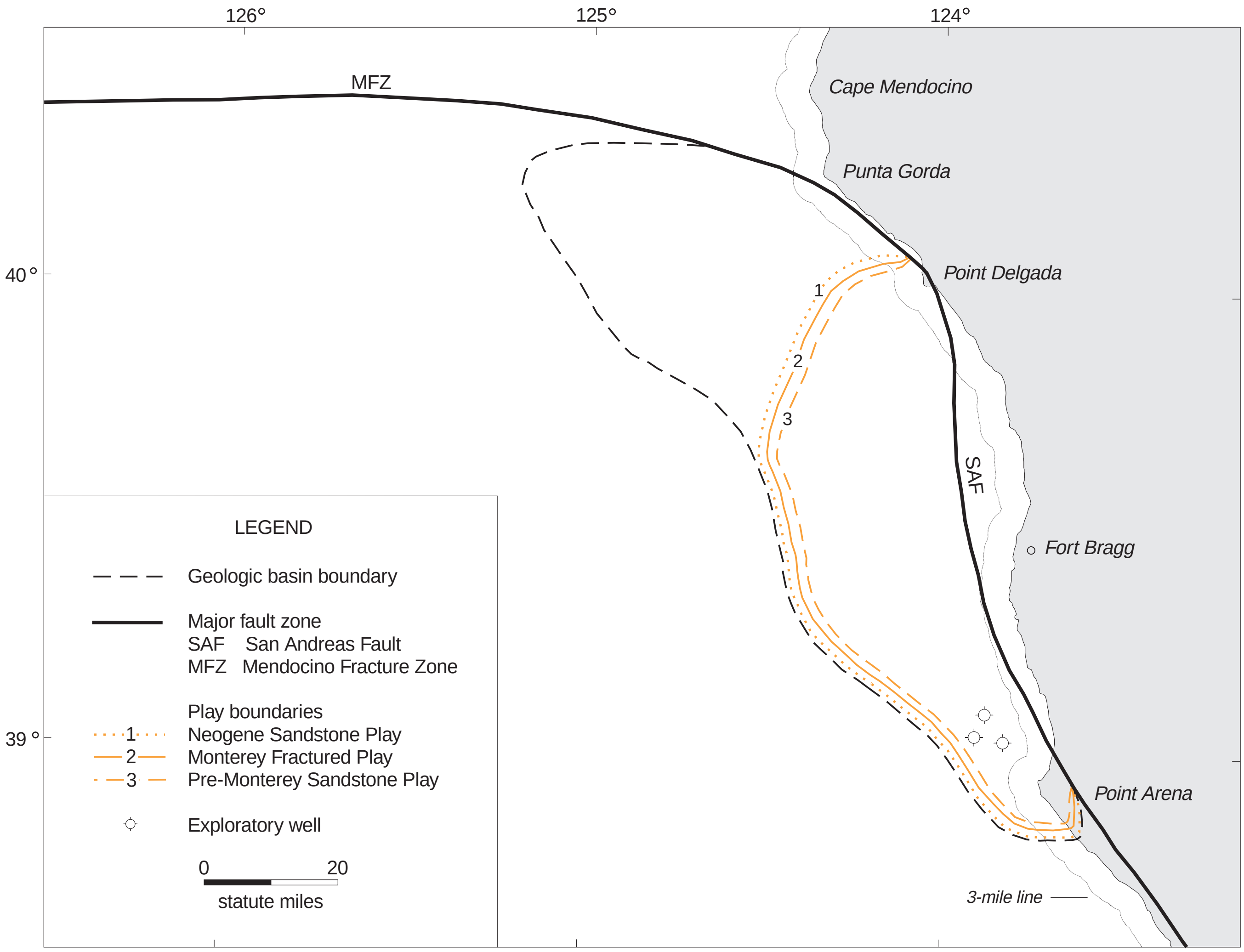

Figure 36. *Map of the Point Arena Basin assessment area showing petroleum geologic plays and wells.*

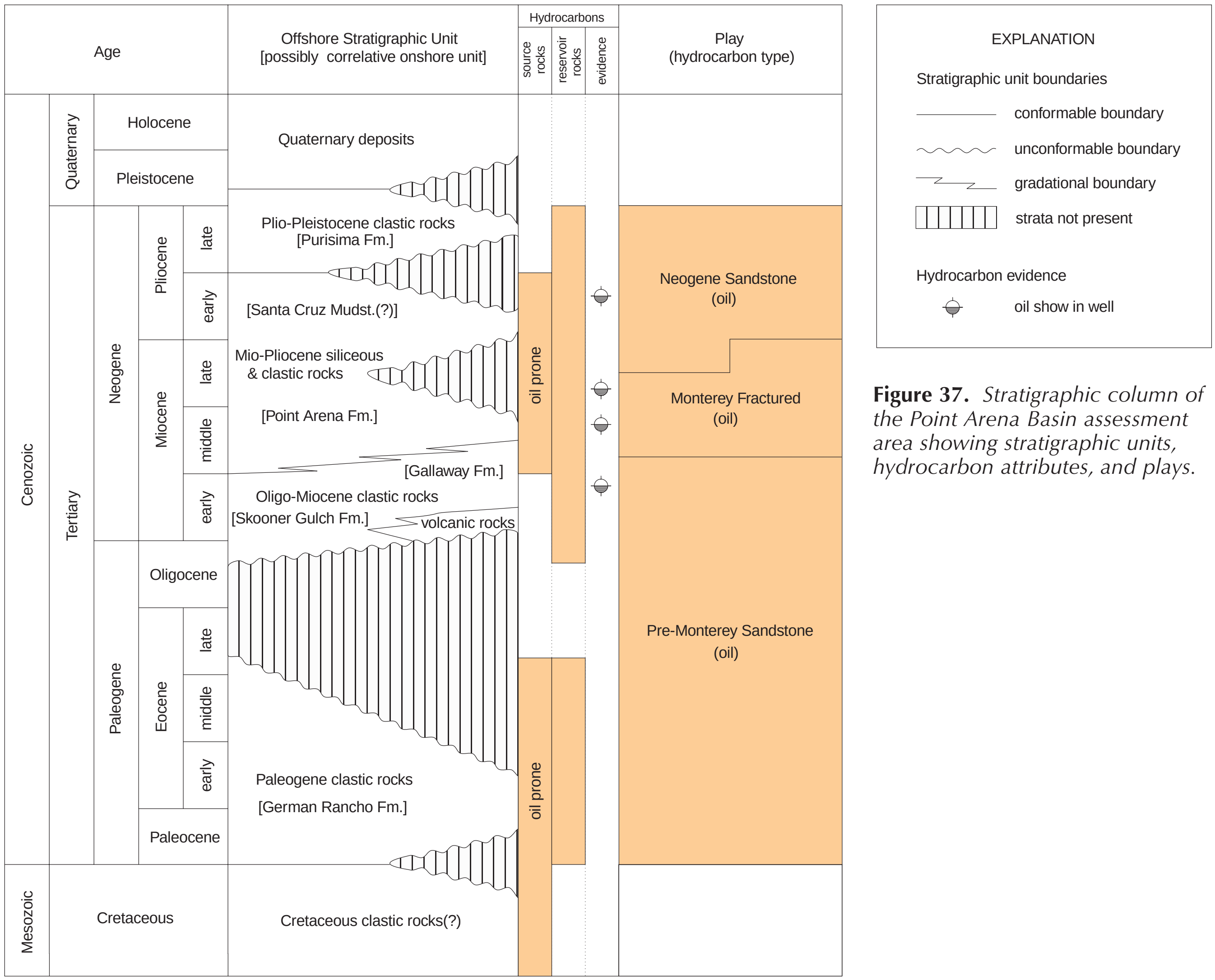

Figure 37. *Stratigraphic column of the Point Arena Basin assessment area showing stratigraphic units, hydrocarbon attributes, and plays.*

(Kulm, von Huene, and others, 1973; McCulloch, 1989). Well cuttings from an offshore exploratory well at the south end of the basin (OCS-P 0033 #1) are quartz-mica schist (Hoskins and Griffiths, 1971). This has been suggested as indicating Salinian basement may extend as far north as Point Arena (Bachman and Crouch, 1987). Others have suggested that the eastern part of the basin may be underlain by exotic terranes with origins thousands of miles to the south (McCulloch, 1987a, b).

The lowest known sedimentary unit in the assessment area is a probable equivalent to the Paleocene to Eocene German Rancho Formation (fig. 37). This unit is composed of 10,000 to 20,000 feet of deep-water turbidite sandstone, siltstone, and mudstone, which may have been deposited in the distal part of a forearc basin (Loomis and Ingle, 1994). Oligocene to Miocene volcanics overlie the Paleogene sediments. The volcanics are stratigraphically discontinuous offshore but are up to 900 feet thick onshore. These are in turn overlain by Neogene basinal sediments, which attain a thickness of over 10,000 feet. The lower Miocene section contains up to 3,000 feet of sandstones, siltstones, and shales deposited in increasing water depths suggestive of early basin formation. These are probable equivalents of the Skooner Gulch and Gallaway Formations described in the onshore (Weaver, 1943; Loomis and Ingle, 1994). These rocks are overlain by middle Miocene siliceous clastic rocks, which are locally named the Point Arena Formation but are lithologically and genetically equivalent to the Monterey Formation as described in the basins to the south. The Monterey Formation is in turn overlain by late Miocene to Pliocene clastic rocks, which are not present onshore. The lower part of this section consists of deep-water siliceous shales with interbedded siltstone and sandstone, and it may be lithologically equivalent to the Sisquoc Formation of the Santa Maria basin. These deposits are unconformably overlain by up to 4,000 feet of Pliocene and Pleistocene siltstones and mudstones with occasional sandstone layers.

Prior to the late Oligocene change in relative plate motions, this area was the site of a convergent plate boundary between the Farallon and North American plates. The paleotectonic setting and the presence of the Paleocene to Eocene turbidites suggest that this area may have been the seaward margin of a forearc basin in an environment similar to that postulated for the Yager complex of the Eel River basin (cf. Underwood, 1985). In the late Oligocene to early Miocene, the Farallon plate was nearly fully subducted and what remained apparently became sutured to the Pacific plate. A result of this was the change of the western margin of central California to a translational margin between the Pacific and North American plates. As elsewhere in central and southern California, volcanism was active in the late Oligocene to early Miocene, associated with the change in relative plate motions. The Neogene basin formed at this time and persists to the present.

The Neogene Point Arena basin is on a steeply sloping part of the continental shelf; it does not have a well-defined and structurally high uplift along the western margin and is, therefore, different from the other basins in the Central California province (Hoskins and Griffiths, 1971; McCulloch, 1987a). The San Andreas fault zone defines the northeast and east margins of the present Point Arena basin and intersects the Mendocino fracture zone directly north of the basin. Neogene and Quaternary tectonics have been dominated by strike-slip, wrench, and thrust faulting associated with these two major right-lateral translational plate boundaries. Major faults and elongate folds generally parallel the northwest-trending San Andreas fault zone, and deformation decreases away from it. Overall folding and faulting patterns suggest that the basin is undergoing transpression, although the orientation of the main trace of the San Andreas fault zone suggests variability between transpression and transtension.

EXPLORATION

During the 1960's, three offshore exploratory wells were drilled in the Point Arena basin (fig. 36). Oil shows were encountered in all three of these wells and in two onshore wells. The offshore area has been studied using a moderately dense to dense grid of seismic-reflection profiles. Silica diagenetic reflectors are seen on the seismic data in the southern part of the basin; their presence suggests that oil generation may have occurred as shallow as 3,000 feet below the seafloor, and that fractured reservoirs are likely in that part of the basin.

PLAYS

For the assessment, three petroleum geologic plays were defined based primarily on reservoir characteristics (figs. 36 and 37). The major play (Monterey Fractured) includes fractured siliceous shales of the Point Arena (Monterey) Formation and the lower siliceous part of the post-Monterey section. The Neogene sandstone play includes the upper, nonsiliceous part of the upper Miocene to Pliocene section. The Pre-Monterey Sandstone play includes sandstones of the German Rancho Formation and lower Miocene sandstones deposited during the Neogene basin formation. The plays are described following this assessment area summary.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Play-specific estimates of undiscovered conventionally recoverable resources have been developed using the subjective assessment method, and these estimates have been statistically aggregated to estimate the total volume of resources in the assessment area. Select data used to develop the estimates are shown in appendix C.

As a result of this assessment, the total volume of undiscovered conventionally recoverable resources in the Point Arena Basin assessment area is expected to be 2.03 Bbbl of oil and 2.14 Tcf of associated gas (mean estimates). This volume may exist in 112 fields with sizes ranging from approximately 80 Mbbl to 510 MMbbl of combined oil-equivalent resources (fig. 38). The majority of these resources (approximately 87 percent on a combined oil-equivalence basis) are estimated to exist in the Monterey Fractured play. The low, mean, and high estimates of resources in the area are listed in table 14 and illustrated in figure 39.

Undiscovered Economically Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the assessment area that may be economically recoverable under various economic scenarios have been developed using the economic assessment method. Select data used to develop the resource estimates are shown in appendix D.

As a result of this assessment, 896 MMbbl of oil and 946 Bcf of associated gas are estimated to be economically recoverable from the Point Arena

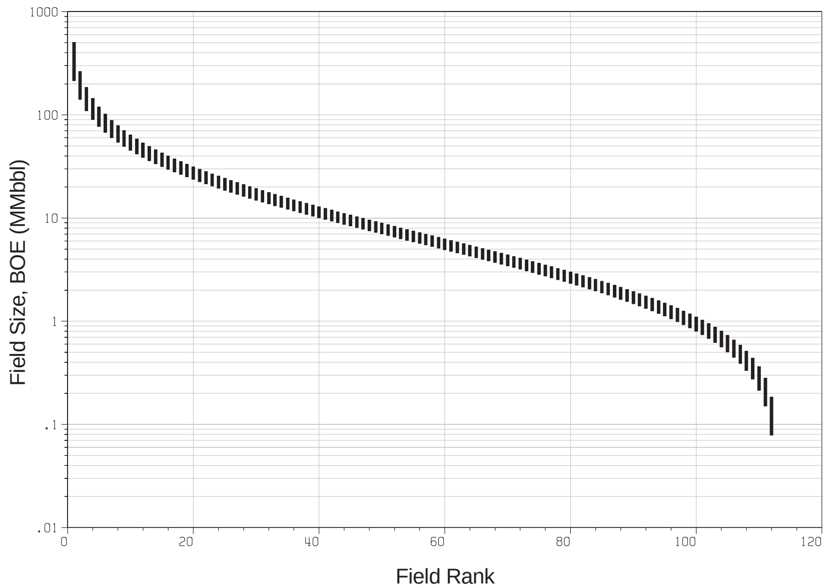

Figure 38. *Field-size rank plot of estimated undiscovered conventionally recoverable resources of the Point Arena Basin assessment area. Sizes of undiscovered fields are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

Table 14. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Point Arena Basin assessment area as of January 1, 1995, by play. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

Play	Oil (MMbbl)			Gas (Bcf)			BOE (MMbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Neogene Sandstone	0	80	230	0	94	267	0	97	277
Monterey Fractured	1,319	1,773	2,355	1,263	1,808	2,629	1,557	2,094	2,794
Pre-Monterey Sandstone	0	177	374	0	240	512	0	220	464
Total Assessment Area	*1,500*	*2,030*	*2,664*	*1,452*	*2,142*	*3,010*	*1,773*	*2,411*	*3,178*

Figure 39. *Cumulative probability plot of estimated undiscovered conventionally recoverable resources of the Point Arena Basin assessment area.*

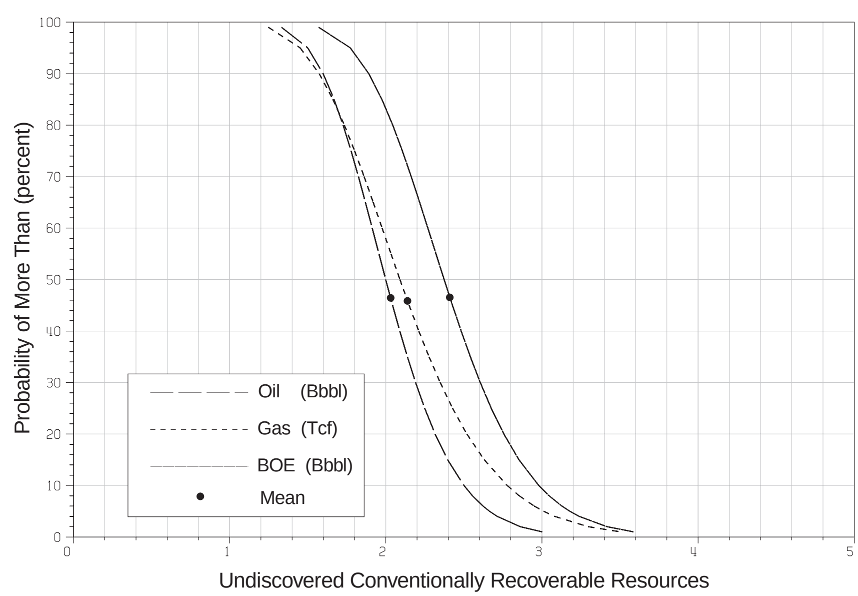

Table 15. *Estimates of undiscovered economically recoverable oil and gas resources in the Point Arena Basin assessment area as of January 1, 1995, by economic scenario. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $25-per-barrel scenario is based on prices of $25 per bbl of oil and $2.94 per Mcf of gas; the $50-per-barrel scenario is based on prices of $50 per barrel of oil and $5.87 per Mcf of gas.*

Economic Scenario	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)
$18 per barrel	896	946	1,064
$25 per barrel	1,205	1,271	1,431
$50 per barrel	1,575	1,661	1,870

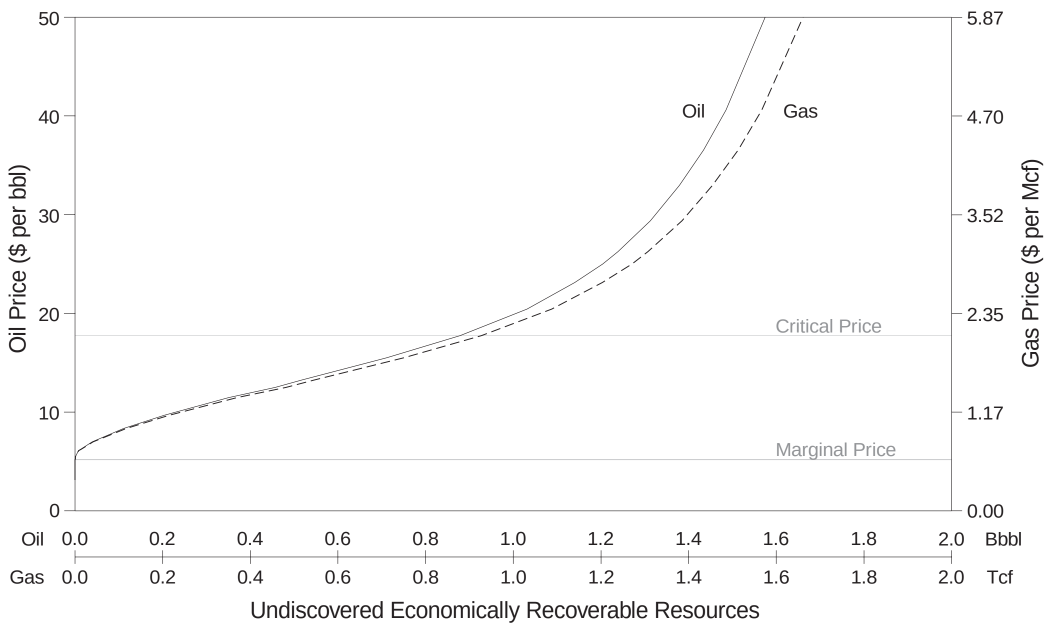

Figure 40. *Price-supply plot of estimated undiscovered economically recoverable resources of the Point Arena Basin assessment area.*

Basin assessment area under economic conditions existing as of this assessment (i.e., the $18-per-barrel economic scenario) (table 15). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions (fig. 40).

Total Resource Endowment

No accumulations of resources have been discovered in the assessment area. Therefore, the aforementioned estimates of undiscovered conventionally recoverable resources compose the estimated total resource endowment of the area.

ACKNOWLEDGMENTS

Initial study of the Point Arena Basin assessment area was performed by Harry Cousminer (Minerals Management Service, retired); his work provided the basis for the play definitions. The following individuals also provided information, insight, and suggestions that improved the quality of the assessment of the Point Arena basin: Jim Crouch (J.K. Crouch and Associates, Inc.) and Mike Brickey and Jim Galloway (Minerals Management Service).

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Zieglar and Cassell, 1978

Neogene Sandstone Play

Play Definition

The Neogene Sandstone play of the Point Arena Basin assessment area is defined to include upper Miocene through Pliocene shelf sandstones in anticlinal, fault, and stratigraphic traps. It is a conceptual play because no hydrocarbons have been detected within the play; however, there is evidence of the presence of oil in expected source rocks in all three offshore wells. The play exists in the central and southern part of the basin from Point Delgada to south of Point Arena; the Federal offshore portion of the play (seaward of the 3-mile line) was evaluated for the assessment (fig. 36). The play is defined on the basis of reservoir rock stratigraphy. Traps are expected to exist in discrete sandstone units within the dominantly siltstone and mudstone section at burial depths to about 5,000 feet.

Petroleum Geologic Characteristics

Source rocks are considered to be Miocene Monterey-equivalent, organic-rich, siliceous shales of the Point Arena Formation and the lower part of the overlying unnamed sedimentary section (fig. 37). The Point Arena Formation is highly petroliferous. A formation test in an offshore well recovered a small amount of 29 °API oil. Total organic carbon content is as high as 5.5 percent, with a median value of about 2 percent. These “Monterey” source rocks are expected to be thermally mature for oil generation as shallow as 3,000 feet below the seafloor based on diagenetic seismic reflectors, which may be indicators of paleotemperature (see Central California province summary). The oil is expected to have migrated upward and laterally along faults, fractures, and the unconformity into the overlying section.

Reservoir rocks for the play are discrete sandstone units (especially fan and fan-channel deposition) within the predominantly siltstones and mudstones of the Miocene to Pliocene section, which overlies the Miocene siliceous rocks. Reservoir sandstones are expected to be of excellent to good quality; porosities in excess of 30 percent were measured in the two offshore wells that penetrate this play.

Potential traps include anticlinal folds, faults, and stratigraphic pinchouts. Structural trends are similar to those in the underlying Miocene units, but folds are more open, of lower amplitude, and less abundant. Mudstones of the Purisima Formation may provide adequate seals.

Exploration

Two of the offshore exploratory wells (OCS-P 0032 #1 and OCS-P 0033 #1) drilled in the 1960’s penetrated rocks of this play. There were no hydrocarbon shows in either of these wells within rocks of this play; however, both wells encountered oil shows in the Monterey-equivalent rocks expected to source this play.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

The resource potential of the play was modeled to include oil and associated gas based on hydrocarbon occurrences in the expected source rocks. Prospect size was modeled using structural closures mapped in the underlying Miocene section; however, prospect density was reduced because the seismic data show less folding and faulting in the Pliocene section. Reservoir parameters were derived in conjunction with data from the other central California coastal basins using the available well data and incorporating some analog data from similar producing Pliocene rocks in southern California.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 80 MMbbl of oil and 94 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 37 pools with sizes ranging from approximately 130 Mbbl to 70 MMbbl of combined oil-equivalent resources (fig. 41). The low, mean, and high estimates of resources in the play are listed in table 14.

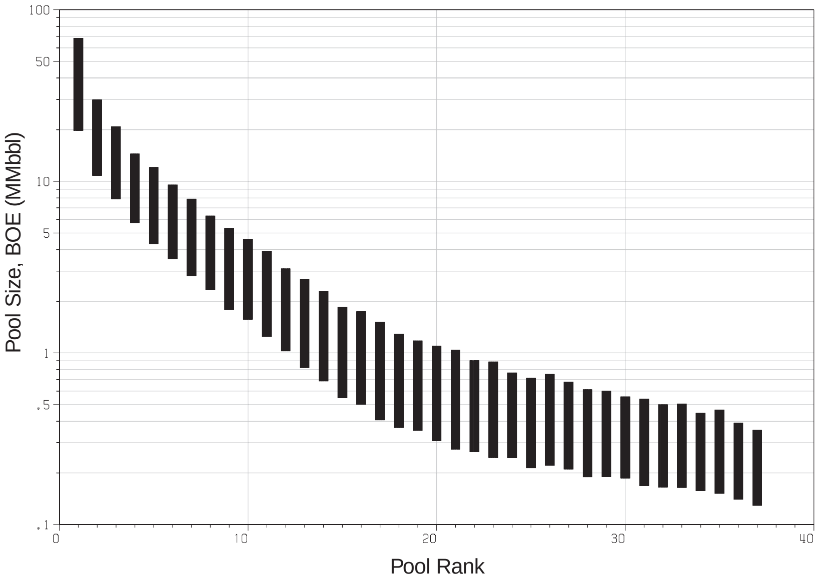


Figure 41. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Neogene Sandstone play, Point Arena Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

MONTEREY FRACTURED PLAY

PLAY DEFINITION

The Monterey Fractured play of the Point Arena Basin assessment area is defined to include fractured siliceous reservoirs in Miocene, Monterey-type siliceous shales of the Point Arena Formation and the lower part of the overlying unnamed sedimentary section. It is a frontier play because no discoveries have been made; however, there is evidence of the presence of oil in rocks of this play in all three offshore exploratory wells. The play exists in the central and southern part of the basin, from Point Delgada to south of Point Arena; the Federal offshore portion of the play (seaward of the 3-mile line) was evaluated for the assessment (fig. 36). The play is defined on the basis of reservoir rock stratigraphy. Traps are expected to exist in fractured shale in anticlinal, fault, and stratigraphic traps at burial depths from about 1,000 to 10,000 feet.

PETROLEUM GEOLOGIC CHARACTERISTICS

Rocks of the Point Arena Formation (described by Weaver, 1943) are considered to be equivalent to the Monterey Formation as it is described for the other central California basins on the basis of age and lithology (fig. 37). Strata immediately overlying the Point Arena Formation (possibly correlative with the Santa Cruz Mudstone; see Bodega and Año Nuevo basin summaries) are also considered to be lithologically equivalent to the Monterey Formation as evidenced by the presence of diagenetic seismic reflectors (which are considered to be indicators of highly siliceous strata). Monterey-type rocks are generally excellent hydrocarbon source rocks and also have potential as fractured reservoirs. The Point Arena Formation is highly petroliferous. One offshore formation test recovered a small amount of 29 °API oil. Total organic carbon content is as high as 5.5 percent with a median value of about 2 percent. These “Monterey” source rocks are expected to be thermally mature for oil generation as shallow as 3,000 feet below the seafloor based on the diagenetic seismic reflectors, which may also be indicators of paleotemperature (see Central California province summary).

Reservoirs are expected to be fractured zones within siliceous shales of the Point Arena Formation (and the lithologically similar overlying strata) and occasional discrete sandstone units interbedded within them. Fractured reservoir quality varies according to the amount of fracturing in the shale section, but Monterey reservoirs in producing basins are found to be excellent reservoirs. Reservoir quality is expected to be good in sandstone interbeds.

Potential traps include fractured zones in anticlinal folds and faults. Fault traps are expected to include subthrust traps. Structural trends are generally northwest-trending with increasing fold amplitudes and structural complexity to the northeast. Trap seals may be provided by less-fractured rocks within the section. Where silica has not been diagenetically altered to quartz (above the lower of two diagenetic reflectors) and in clastic-rich areas, decreased fracture density is expected; heavy oil in these areas may be trapped, thus creating a tar seal.

Exploration

All three offshore exploratory wells (OCS-P 0030 #1, OCS-P 0032 #1, and OCS-P 0033 #1) penetrated rocks of this play. There were oil shows in the Point Arena Formation in all these wells; one well (OCS-P 0030 #1) had oil shows in the overlying strata (Santa Cruz Mudstone(?)).

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

The resource potential of the play was modeled to include oil and associated gas based on the hydrocarbon shows. Prospect sizes and the number of prospects were estimated based on structural closures mapped using a dense grid of seismic data. Reservoir parameters were derived in conjunction with data from the other central California coastal basins using the available well data and incorporating some analog data from producing Monterey fields in southern California.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 1.77 Bbbl of oil and 1.81 Tcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 139 pools with sizes ranging from approximately 50 Mbbl to 665 MMbbl of combined oil-equivalent resources (fig. 42). The low, mean, and high estimates of resources in the play are listed in table 14.

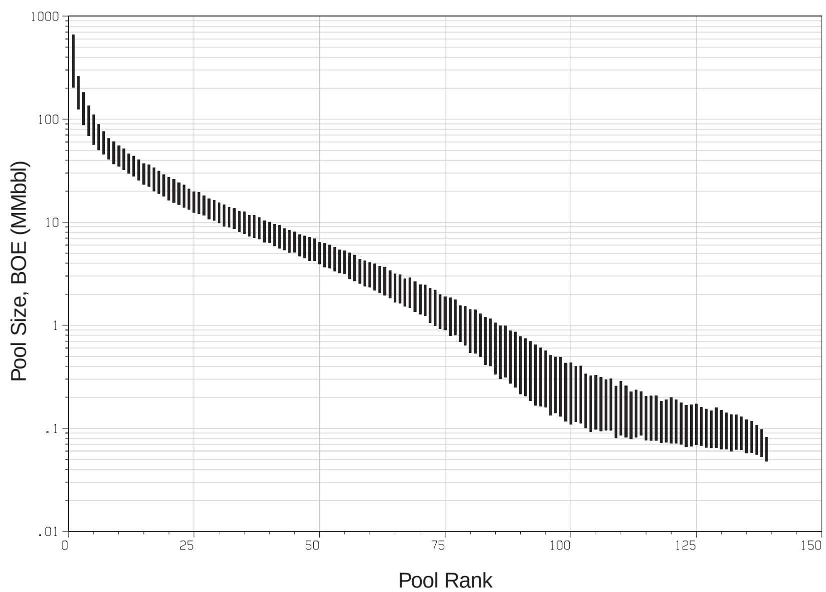


Figure 42. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Monterey Fractured play, Point Arena Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

Pre-Monterey Sandstone Play

Play Definition

The Pre-Monterey Sandstone play of the Point Arena Basin assessment area is defined to include Paleocene to lower Miocene sandstones in anticlinal, fault, and stratigraphic traps. It is a frontier play because no discoveries have been made; however, there is evidence of the presence of oil in two offshore wells and two onshore wells. The play exists in the central and southern part of the basin, from Point Delgada to south of Point Arena; the Federal offshore portion of the play (seaward of the 3-mile line) was evaluated for the assessment (fig. 36). The play is defined on the basis of reservoir rock stratigraphy. Traps are expected to exist in discrete sandstone units within the mostly siltstone and mudstone section at burial depths from about 1,000 to 15,000 feet.

Petroleum Geologic Characteristics

Sedimentary units present in offshore wells have been tentatively correlated (by MMS) with the onshore German Rancho, Skooner Gulch, and Gallaway Formations. Shales within the Paleocene to Eocene German Rancho Formation and Oligocene to Miocene Skooner Gulch and Gallaway Formation equivalents are considered to be the primary hydrocarbon sources for this play. Onshore samples of these shales indicate fair to good generative potential for oil with total organic carbon content of about 0.5 to 4.3 percent (Crouch, Bachman, and Associates, Inc., 1987). The German Rancho Formation has potential for nonassociated gas as well as oil generation (Crouch, Bachman, and Associates, Inc., 1987). There is also some potential for sourcing of this play from the overlying Monterey-type rocks; these source rocks are expected to be thermally mature for oil generation as shallow as 3,000 feet below the seafloor based on diagenetic seismic reflectors, which may be indicators of paleo-temperature (see Central California province summary).

Potential reservoirs are discrete sandstone units deposited in shelf and fan sequences within the section. The Skooner Gulch and Gallaway Formation equivalents are expected to have very good to excellent reservoir quality (porosities of about 15 to 25 percent have been measured in offshore wells. German Rancho Formation sandstones are considered to be of fair reservoir quality with moderate porosity (about 13 percent).

Potential traps include anticlinal folds and faults.Fault traps are expected to include subthrust traps. Structural trends are generally northwest-trending with increasing fold amplitudes and structural complexity to the northeast. Trap seals may be provided by interbedded shales and mudstones.

EXPLORATION

All three offshore exploratory wells (OCS-P 0030 #1, OCS-P 0032 #1, and OCS-P 0033 #1) penetrated rocks of this play. There were oil shows within the Gallaway Formation equivalent in two of these wells (OCS-P 0030 #1 and OCS-P 0032 #1). There were oil shows in the Skooner Gulch Formation equivalent and both oil and gas shows in the German Rancho Formation in an onshore well (Sun Lepori #1).

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

The resource potential of the play was modeled to include oil and associated gas based on the hydrocarbon shows. Although there is some potential for nonassociated-gas sourcing within the German Rancho Formation, it was not modeled; however, its expected contribution has been considered and included within the modeled limits for associated gas. Prospect sizes and the number of prospects were estimated based on structural closures mapped using a dense grid of seismic data. Reservoir parameters were derived in conjunction with data from the other coastal basins in the Central California province using the available well data and incorporating some analog data from producing fields in southern California.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 177 MMbbl of oil and 240 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 128 pools with sizes ranging from approximately 25 Mbbl to 85 MMbbl of combined oil-equivalent resources (fig. 43). The low, mean, and high estimates of resources in the play are listed in table 14.

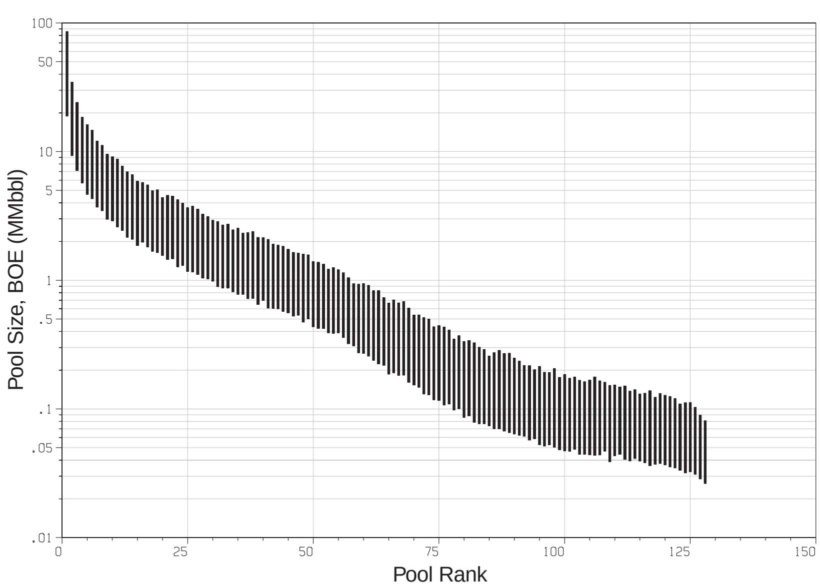


Figure 43. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Pre-Monterey Sandstone play, Point Arena Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

BODEGA BASIN

by Catherine A. Dunkel

LOCATION

The Bodega basin is located between the Point Arena and Año Nuevo basins in the Central California province (fig. 33). This northwest-trending basin extends from Half Moon Bay to offshore Gualala, California (fig. 44). The basin is approximately 110 miles long and 20 miles wide, and occupies an area of approximately 1,700 square miles. The western margin of the basin is defined by the Farallon-Pigeon Point high; the basin is bounded on the east by the San Gregorio and San Andreas fault zones. A small portion of the basin lies in State waters and is exposed onshore at the Point Reyes Peninsula.

The Bodega Basin assessment area comprises only the Federal offshore portion of the basin (i.e., seaward of the 3-mile line). Water depths in the assessment area range from approximately 30 feet at the 3-mile line offshore San Francisco to approximately 1,000 feet near the transition between the continental shelf and slope north of the Farallon Islands.

GEOLOGIC SETTING

The Bodega basin, as described here, comprises the "Bodega basin" and the offshore portion of the "Santa Cruz basin" (as these basins were described by Hoskins and Griffiths (1971)); the latter area has

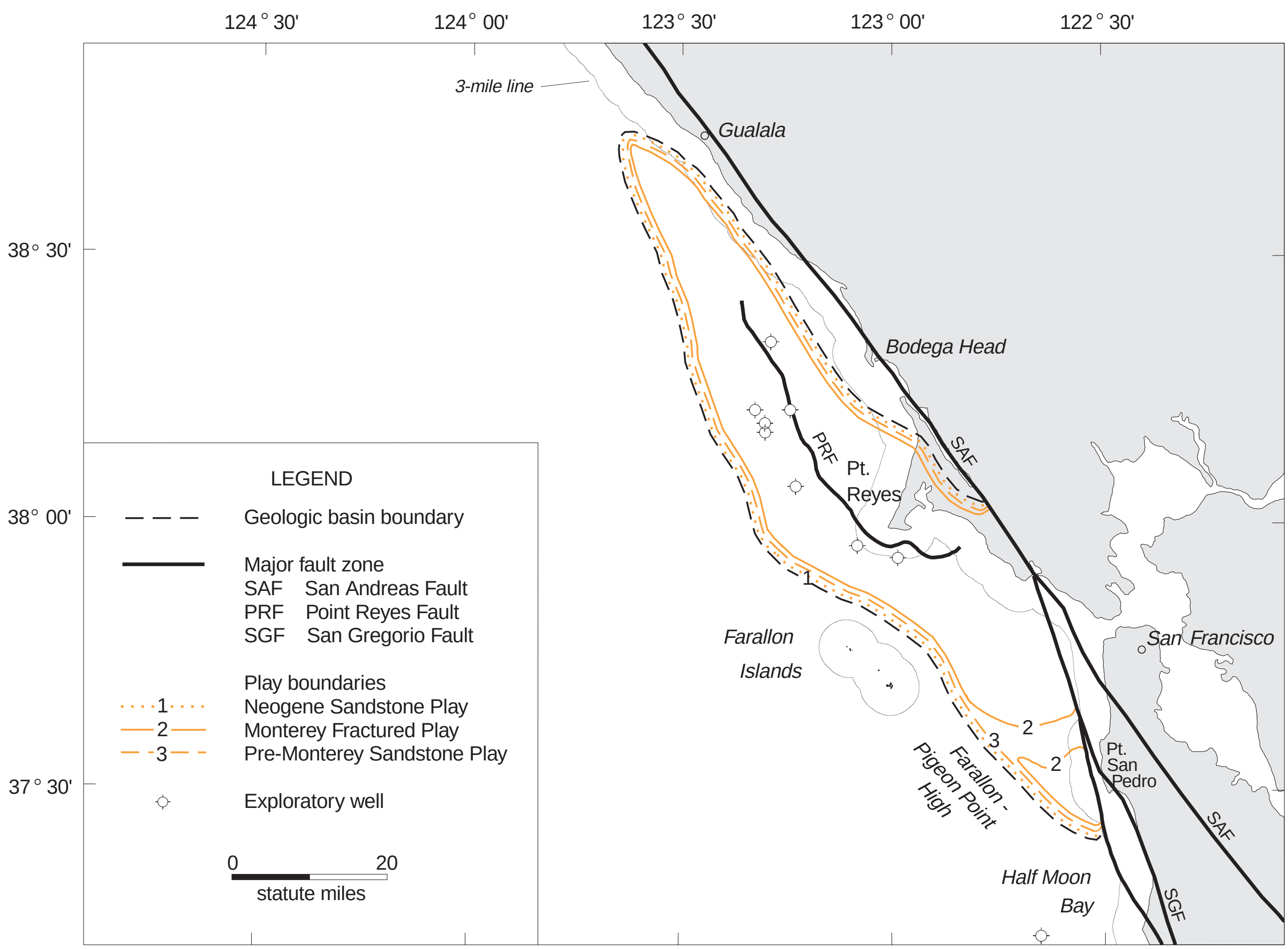


Figure 44. *Map of the Bodega Basin assessment area showing petroleum geologic plays and wells.*

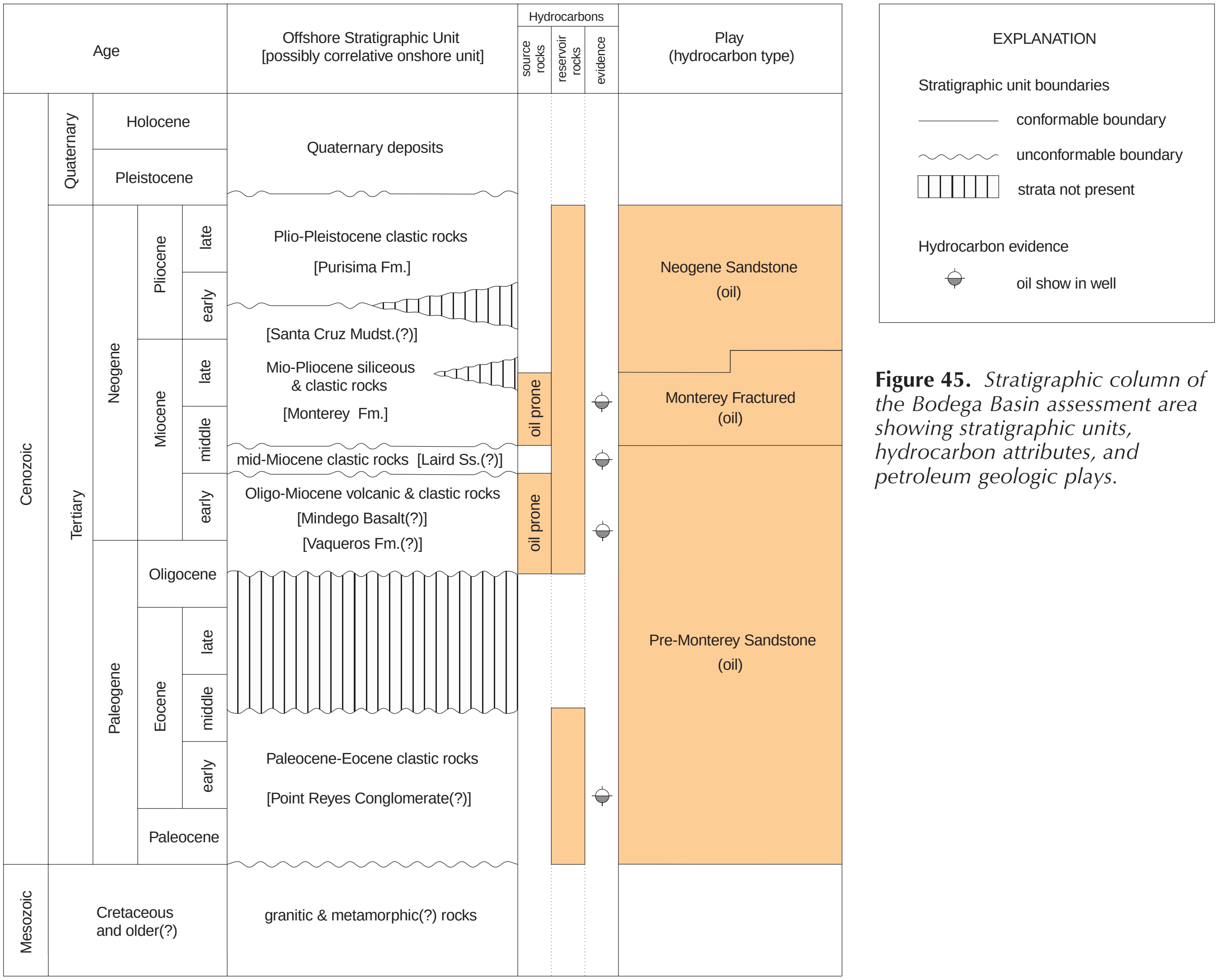


Figure 45. *Stratigraphic column of the Bodega Basin assessment area showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays.*

also been described as the offshore "La Honda basin" (Webster and Yenne, 1987). These areas appear to have been a continuous depocenter that is bisected in the vicinity of Point San Pedro by a northeast-trending, intrabasinal high.

The Cenozoic stratigraphic succession of the Bodega basin area indicates that the area has undergone a complex history of subsidence, sedimentary deposition, volcanism, uplift, and erosion (McCulloch, 1987b). The oldest rocks penetrated by offshore exploratory wells are Cretaceous granites similar to those exposed on the Farallon Islands and Point Reyes Peninsula (fig. 45). These rocks of the Salinia terrane are overlain offshore by Paleocene and Eocene conglomeratic rocks similar (and possibly correlative[6]) to submarine fan-channel deposits exposed at Point Reyes. The initial subsidence and formation of the Bodega basin proper may be recorded by the Paleocene and Eocene strata; alternatively, these strata may be a local remnant of a larger body of Cretaceous and Paleogene strata (i.e., including strata in the adjacent Point Arena and Año Nuevo basins) that were deposited, uplifted, and eroded prior to the formation of the basin. Following an episode of Paleogene uplift and

[6] Strata penetrated in the offshore wells of the Bodega basin were initially described by Hoskins and Griffiths (1971) and have been subsequently described by Zieglar and Cassell (1978) and McCulloch (1987b). Webster and Yenne (1987) assigned onshore formation names to the offshore strata based on lithologic and biostratigraphic (i.e., benthic foraminiferal) data from offshore well samples (fig. 45); however, given the limited number of wells and samples in the offshore Bodega basin, and the lack of demonstrated physical continuity between the offshore and onshore strata, these assignments and onshore-offshore correlations are uncertain. Therefore, the onshore-offshore correlations cited here and in figure 45 are considered to be possible correlations (and in some cases, possible partial correlations).

erosion (or nondeposition of middle Eocene to Oligocene strata), an episode of late Oligocene to early Miocene subsidence occurred, during which interbedded volcanic and marine clastic strata of early Miocene and possibly Oligocene age were deposited; the volcanic rocks are lithologically and temporally similar to those in other California coastal basins and may record a middle Tertiary extensional event that produced volcanism along the continental margin (McCulloch, 1987b). The bulk of the Bodega basin fill consists of a thick sequence of middle to upper Miocene marine clastic, siliceous, and siliciclastic rocks that record a middle Miocene transgression, subsequent subsidence, and hemipelagic siliceous deposition. Some of the siliceous deposits appear to have been uplifted and eroded during the late Miocene and early Pliocene. The uneroded siliceous rocks are overlain by Pliocene and Pleistocene marine clastic rocks and semiconsolidated Quaternary marine deposits. These major Tertiary stratigraphic sequences, which were deposited in marine shelf and slope settings, are separated by boundaries that are evident on seismic-reflection profiles. The boundaries are generally unconformable along the uplifted margins of the basin and are locally unconformable at intrabasinal highs.

The structural axis and many faults and folds in the basin are predominantly northwest-trending and subparallel (or at low angles) to the San Andreas fault zone; this suggests that the origin and early deformational history of the basin may have been largely controlled by this right-lateral strike-slip fault (Wilcox and others, 1973; Blake and others, 1978). However, the variable orientation of many fold and fault trends suggests that some structural features may be genetically related to the San Gregorio fault and/or late Cenozoic compression; recent (and possibly ongoing) compression along the Point Reyes fault has produced large vertical displacement of basement and overlying strata in the central portion of the basin (Hoskins and Griffiths, 1971; McCulloch, 1987b). The presence of rigid granitic basement rocks throughout most (if not all[7]) of the Bodega basin may have affected the structural style of overlying basinal strata (Hoskins and Griffiths, 1971); seismic-reflection profiles suggest that folds in the stratigraphic fill of the Bodega basin are broader and of less amplitude than in adjacent basins floored wholly or partially by less-rigid rocks of the Franciscan Complex.

[7] It has been suggested that basement rocks of the Bodega basin may include both granitic and metamorphic rocks of the Salinia terrane (McCulloch, 1987b); however, the presence of metamorphic basement rocks in the basin has not been confirmed.

Petroleum Geology

Knowledge of the petroleum geology of the basin has been garnered from 10 offshore exploratory wells drilled from nine sites in the northern and central portions of the basin (fig. 44) and from a moderately dense grid of seismic-reflection profiles. Data from onshore wells and outcrops, and published sources were also considered. The primary petroleum source rocks for all plays in the basin are presumed to be rocks of the Miocene Monterey Formation, by analogy with several California coastal basins. Although organic geochemical data are lacking for Monterey rocks in the Bodega basin, the presence of organic-rich, thermally mature source rocks is suggested by oil and gas shows in Monterey and other strata in the basin. Structurally anomalous reflectors on seismic-reflection profiles, density contrasts on well logs, and mineralogic compositions of well samples suggest that diagenetic alteration of opal-CT-phase silica to quartz-phase silica has occurred at burial depths of approximately 4,300 feet. If the temperature required for this mineralogic conversion is coincident with the onset of oil generation in Monterey rocks (as described in the Central California province discussion), thermally mature Monterey rocks may exist over much of the basin. Although Monterey rocks in the Bodega basin are thinner and less extensive than in adjacent basins (due to uplift and erosion), the original stratigraphic thickness and ultimate petroleum generative potential of these strata are presumed to have been comparable.

Shows in some of the offshore wells indicate that oil has generated and migrated in the Bodega basin, although the existence of a viable petroleum system (i.e., in which petroleum has generated, migrated, and accumulated within traps) is somewhat speculative due to the limited number and magnitude of the shows. Oil seeps and bituminous sandstones are abundant in the onshore Point Reyes area, and minor shows of oil and gas have been encountered in some onshore wells (Galloway, 1977; Stanley, 1995b); however, no commercial production has been established.

The petroleum potential of the offshore portion of the basin may be most prospective in the vicinity of the Point Reyes fault, where large vertical displacement has created an anomalously thick section of Monterey strata and a number of potential structural traps. However, the absence of significant shows in the offshore wells (many of which were drilled near the fault) suggests that this vertically continuous fault may have been a barrier (rather than pathway) to migrating hydrocarbons.

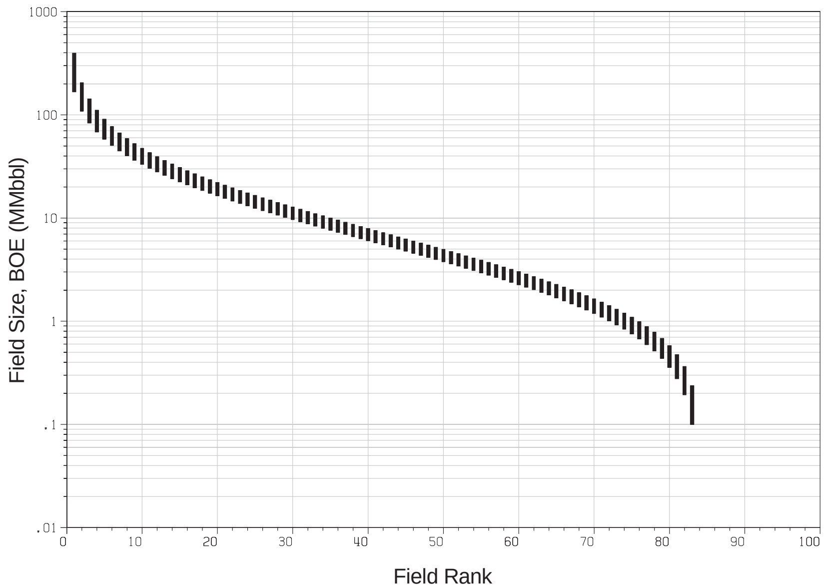


Figure 46. *Field-size rank plot of estimated undiscovered conventionally recoverable resources of the Bodega Basin assessment area. Sizes of undiscovered fields are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

PLAYS

Three petroleum geologic plays, defined on the basis of reservoir rock stratigraphy, have been assessed in the Federal offshore portion of the basin (figs. 44 and 45). These are (1) the Neogene Sandstone play (upper Miocene and Pliocene clastic reservoirs), (2) the Monterey Fractured play (middle and upper Miocene fractured siliceous reservoirs), and (3) the Pre-Monterey Sandstone play (Paleocene through middle Miocene clastic reservoirs).

Tertiary sedimentary and volcanic rocks that are stratigraphically similar (and possibly correlative) to some of the strata included in these plays exist in the State offshore and onshore areas of the basin. These adjacent rocks compose the Point Reyes Oil play of the Central Coastal province, which has been described and assessed by the U.S. Geological Survey (Stanley, 1995b).

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Play-specific estimates of undiscovered conventionally recoverable resources have been developed using the subjective assessment method, and these estimates have been statistically aggregated to estimate the total volume of resources in the assessment area. Select data used to develop the resource estimates are shown in appendix C.

As a result of this assessment, the total volume of undiscovered conventionally recoverable resources in the Bodega Basin assessment area is estimated to be 1.42 Bbbl of oil and 1.57 Tcf of associated gas (mean estimates). This volume may exist in 83 fields with sizes ranging from approximately 100 Mbbl to 400 MMbbl of combined oil-equivalent resources (fig. 46). The majority of these resources (approximately 76 percent on a combined oil-equivalence basis) are estimated to exist in the Monterey Fractured play. The low, mean, and high estimates of resources in the assessment area are listed in table 16 and illustrated in figure 47.

Undiscovered Economically Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the assessment area that may be economically recoverable under various economic scenarios have been developed using the economic assessment method. Select data used to develop the resource estimates are shown in appendix D.

As a result of this assessment, 1.03 Bbbl of oil and 1.13 Tcf of associated gas are estimated to be economically recoverable from the Bodega Basin assessment area under economic conditions existing as of this assessment (i.e., the $18-per-barrel economic scenario) (table 17). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions (fig. 48).

Table 16. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Bodega Basin assessment area as of January 1, 1995, by play. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

Play	Oil (MMbbl)			Gas (Bcf)			BOE (MMbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Neogene Sandstone	0	54	166	0	59	180	0	65	195
Monterey Fractured	802	1,094	1,524	774	1,139	1,639	945	1,297	1,797
Pre-Monterey Sandstone	0	272	553	0	370	824	0	338	694
Total Assessment Area	*972*	*1,420*	*1,979*	*1,004*	*1,568*	*2,300*	*1,160*	*1,699*	*2,374*

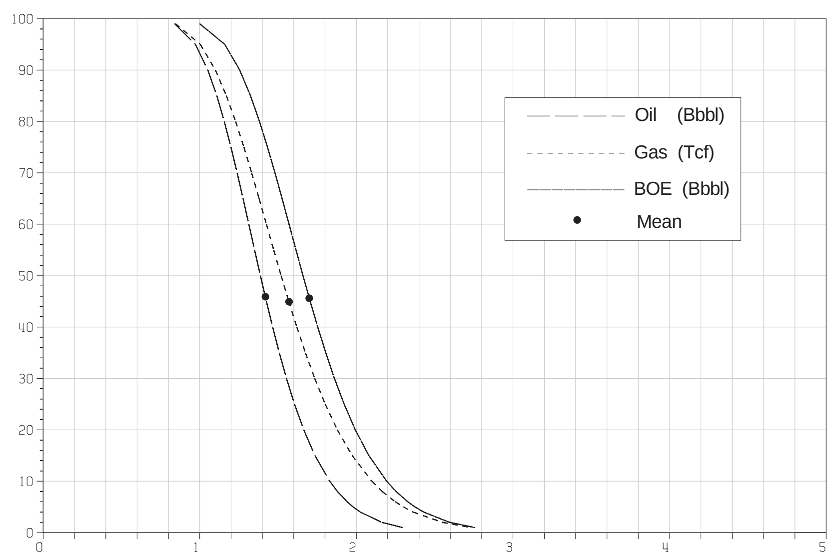


Figure 47. *Cumulative probability plot of estimated undiscovered conventionally recoverable resources of the Bodega Basin assessment area.*

Total Resource Endowment

No accumulations of resources have been discovered in the assessment area. Therefore, the aforementioned estimates of undiscovered conventionally recoverable resources compose the estimated total resource endowment of the area.

Acknowledgments

The author thanks Richard Stanley and James Crouch for sharing information and insight regarding the geology and petroleum potential of the central California coastal area and the Bodega basin, Harold Cousminer for initial study that led to the play definitions, and Scott Drewry for preparing figures.

Additional References

Crouch, Bachman, and Associates, Inc., 1985
Crouch, Bachman, and Associates, Inc., 1988b
Heck and others, 1990
J.K. Crouch and Associates, Inc., 1988
McCulloch, 1989
McLean and Wiley, 1987
Ogle, 1981
Webster and others, 1988

Table 17. *Estimates of undiscovered economically recoverable oil and gas resources in the Bodega Basin assessment area as of January 1, 1995, by economic scenario. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $25-per-barrel scenario is based on prices of $25 per bbl of oil and $2.94 per Mcf of gas; the $50-per-barrel scenario is based on prices of $50 per barrel of oil and $5.87 per Mcf of gas.*

Economic Scenario	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)
$18 per barrel	1,026	1,133	1,228
$25 per barrel	1,142	1,261	1,367
$50 per barrel	1,272	1,405	1,522

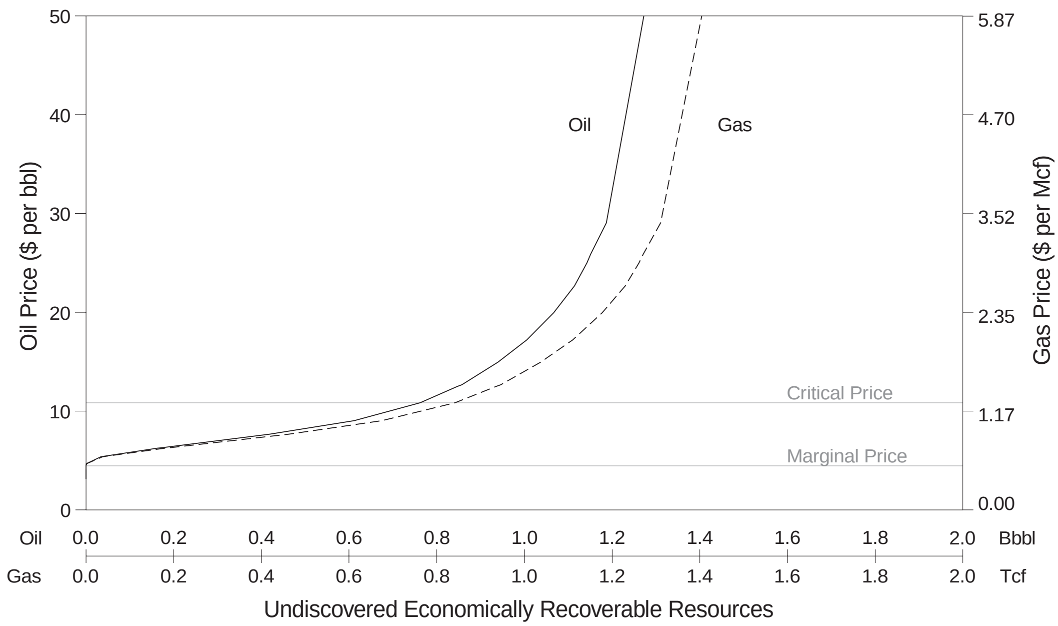


Figure 48. *Price-supply plot of estimated undiscovered economically recoverable resources of the Bodega Basin assessment area.*

NEOGENE SANDSTONE PLAY

PLAY DEFINITION

The Neogene Sandstone play of the Bodega Basin assessment area is defined to include accumulations of oil and associated gas in upper Miocene and Pliocene marine clastic rocks overlying the Monterey Formation. This basin-wide play encompasses an area of approximately 1,700 square miles (fig. 44) and exists at burial depths as great as 4,300 feet.

PETROLEUM GEOLOGIC CHARACTERISTICS

Potential petroleum source rocks for the play are oil-prone Monterey rocks (fig. 45), which may be thermally mature throughout the basin. The oil is expected to be heavy (15 to 20 °API) and high in sulfur, by analogy with Monterey-sourced oils produced from several California coastal basins. Speculatively, reservoirs in this play may contain a greater proportion of gas due to selective upward migration of free associated gas from underlying generative Monterey rocks. No other potential source rocks are presumed to exist for this play.

Potential reservoir rocks consist of upper Miocene to lower Pliocene sandstones and siltstones (possibly correlative in part to the Santa Cruz Mudstone) and lower to upper Pliocene sandstones and siltstones (possibly correlative in part to the Purisima Formation) (fig. 45). Core and log analyses indicate that the rocks have fair to good reservoir quality. Migration of oil and associated gas from underlying generative Monterey rocks is presumed to have occurred along fractures, faults, and unconformities.

Traps are presumed to be both structural and stratigraphic. Structural traps include anticlines, fault truncations, and faulted anticlines. Some potential structural traps have been mapped with seismic profiles; however, much of the post-Monterey section is relatively undeformed and lacks abundant and complex structural traps. Stratigraphic traps may exist at pinchouts of sandstone interbeds and where sandstones wedge out along the Farallon-Pigeon Point high. Seals may be provided by faults and unconformities and by Pliocene and Pleistocene mudstones and shales.

Exploration

Eight exploratory wells have penetrated the Federal offshore portion of this frontier play. No visible shows of oil were observed; however, some indirect indications of oil (i.e., through solvent, fluorescence, and odor) were encountered in a few wells.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

Structural information from seismic profiles, stratigraphic information from the exploratory wells, and additional data from geologically analogous plays in the adjacent Point Arena and Año Nuevo basins were used to estimate the volume and number of pools in this play. The oil recovery factor (oil yield) was estimated by analogy with several producing fields in the Pico-Repetto Sandstone play of the Santa Barbara-Ventura basin; the solution gas-to-oil ratio was estimated by analogy with select Monterey-producing fields in the onshore and offshore portions of the Santa Maria basin. The viability of this play (play chance) is estimated to be good; the probability that at least one undiscovered accumulation exists is predicted to be 60 percent. However, many prospects are expected to lack adequate fill (i.e., the volume of generated hydrocarbons may be insufficient to fill all traps), reservoir rocks, and/or seal. Therefore, the prospect success ratio (conditional prospect chance) is estimated to be poor; only 30 percent of the prospects are predicted to be pools.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 54 MMbbl of oil and 59 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 27 pools with sizes ranging from approximately 150 Mbbl to 50 MMbbl of combined oil-equivalent resources (fig. 49). The low, mean, and high estimates of resources in the play are listed in table 16.

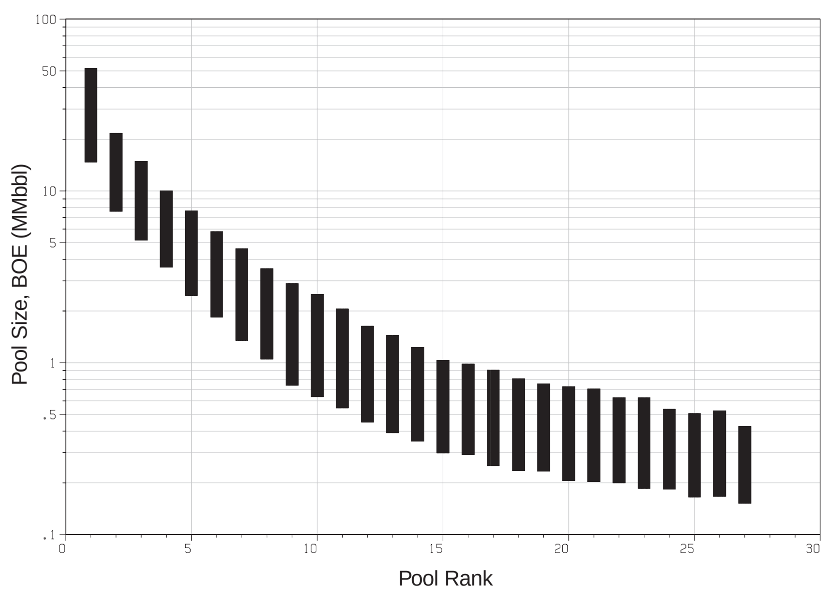


Figure 49. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Neogene Sandstone play, Bodega Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

MONTEREY FRACTURED PLAY

PLAY DEFINITION

The Monterey Fractured play of the Bodega Basin assessment area is defined to include accumulations of oil and associated gas in middle and upper Miocene fractured siliceous rocks within and overlying the Monterey Formation. This play exists over most of the basin, but is not present along an intrabasinal high near Point San Pedro, where Monterey strata have been uplifted and eroded. The play covers an area of approximately 1,650 square miles (fig. 44) and exists at burial depths as great as 6,000 feet.

PETROLEUM GEOLOGIC CHARACTERISTICS

Potential petroleum source rocks for the play are oil-prone Monterey rocks (fig. 45), which may be thermally mature throughout the basin. The oil is expected to be heavy (15 to 20 °API) and high in sulfur, by analogy with Monterey-sourced oils produced from several California coastal basins. Speculatively, reservoirs in the upper portion of this play may contain lighter, gas-enriched oil, due to selective upward migration of higher-viscosity oil and free associated gas.

Potential reservoir rocks consist of middle to upper Miocene fractured siliceous shales and cherts of the Monterey Formation and overlying strata (possibly correlative in part to the Santa Cruz Mudstone) (fig. 45). Mineralogic compositions of well samples indicate that the original biogenic (opal-A) silica in these rocks has been diagenetically altered to opal-CT and quartz. Core and log analyses indicate that the rocks have good to excellent reservoir quality, and that the best potential reservoir rocks may exist below the opal-CT-quartz diagenetic boundary, where fracture density and porosity may be enhanced. Multidirectional migration of oil and associated gas from in situ generative Monterey rocks is presumed to have occurred along fractures and faults, some of which breach the diagenetic boundary.

Predominantly structural traps are expected to exist in the play and to include anticlines, fault truncations, and simple to complexly faulted anticlines. Several potential structural traps have been mapped with seismic profiles. Speculatively, some stratigraphic traps formed by pinchouts of siliciclastic interbeds may exist in the play. Seals may be provided by fractures, faults, and unconformities; by an inferred "tar accumulation zone" at the diagenetic boundary; and by mudstones and shales of the overlying Pliocene section.

EXPLORATION

Nine exploratory wells have penetrated the Federal offshore portion of this frontier play. Shows of free tarry oil and tar stains on fractures were encountered within the Monterey section in some wells.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

Structural information from seismic profiles, stratigraphic information from the exploratory wells, and additional data from geologically analogous plays in the adjacent Point Arena and Año Nuevo basins were used to estimate the volume and number of pools in this play. The oil recovery factor (oil yield) and solution gas-to-oil ratio were estimated by analogy with select Monterey-producing fields in the Federal offshore portion of the Santa Maria and Santa Barbara-Ventura basins. The viability of this play (play chance) is estimated to be assured; the probability that at least one undiscovered accumulation exists is predicted to be 100 percent. However, some prospects are expected to lack adequate fill (i.e., the volume of generated hydrocarbons may be insufficient to fill all traps), reservoir rocks, and/or seal. Therefore, the prospect success ratio (conditional prospect chance) is estimated to be fair; 50 percent of the prospects are predicted to be pools.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 1.09 Bbbl of oil and 1.14 Tcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 126 pools with sizes ranging from approximately 75 Mbbl to 420 MMbbl of combined oil-equivalent resources (fig. 50). The low, mean, and high estimates of resources in the play are listed in table 16.

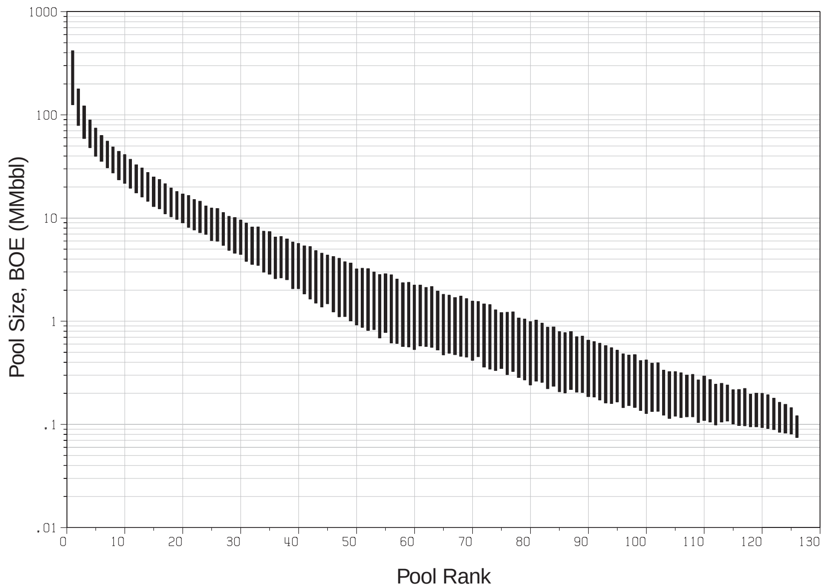


Figure 50. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Monterey Fractured play, Bodega Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

Pre-Monterey Sandstone Play

Play Definition

The Pre-Monterey Sandstone play of the Bodega Basin assessment area is defined to include accumulations of oil and associated gas in Paleogene and Neogene marine clastic rocks underlying the Monterey Formation. This basin-wide play encompasses an area of approximately 1,700 square miles (fig. 44) and exists at burial depths of approximately 600 to more than 10,000 feet.

Petroleum Geologic Characteristics

The primary potential petroleum source rocks for the play are oil-prone Monterey rocks (fig. 45), which may be thermally mature throughout the basin. The oil is expected to be heavy (15 to 20 °API) and high in sulfur, by analogy with Monterey-sourced oils produced from several California coastal basins. Other potential source rocks may exist in pre-Monterey rocks of this play; however, the generative potential of these in situ source rocks is considered less prospective than the overlying Monterey rocks. Oil from pre-Monterey rocks, if generated, is expected to have higher gravity (25 to 45 °API), lower sulfur content, and a greater proportion of dissolved gas, based on analogy with Paleogene-sourced oils produced from the Santa Barbara-Ventura and onshore La Honda basins.

Potential reservoir rocks consist of Paleocene to middle Eocene conglomeratic sandstones (possibly correlative to the Point Reyes Conglomerate), lower Miocene and possibly Oligocene sandstones and siltstones (possibly correlative in part to the Mindego Basalt and Vaqueros Formation), and middle Miocene sandstones (possibly correlative in part to the Laird Sandstone) (fig. 45). Core and log analyses suggest that these rocks may have fair reservoir quality, but that porosity and permeability may be diminished by the presence of volcaniclastic clays, compaction, and cementation. Migration of oil and associated gas from overlying generative Monterey rocks (and generative pre-Monterey rocks, if they exist) is presumed to have occurred along fractures, faults, and unconformities.

Traps are presumed to be both structural and stratigraphic. Structural traps include anticlines, fault truncations, and simple to complexly faulted anticlines. Several potential structural traps have been mapped with seismic profiles. Stratigraphic traps may exist at pinchouts of sandstone interbeds and where sandstones wedge out along the Farallon-Pigeon Point high. Seals may be provided by faults and unconformities, volcanic rocks and shales of this play, and siliceous shales and cherts of the overlying Miocene and Pliocene sections.

EXPLORATION

Nine exploratory wells have penetrated the Federal offshore portion of this frontier play. Weak oil shows and log analysis indicate the presence of hydrocarbons in a few wells.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

Structural information from seismic profiles, stratigraphic information from the exploratory wells, and additional data from geologically analogous plays in the adjacent Point Arena and Año Nuevo basins were used to estimate the volume and number of pools in this play. The oil recovery factor (oil yield) was estimated by analogy with select producing fields in the Sespe-Alegria-Vaqueros Sandstone play in the Santa Barbara-Ventura basin. This analog data set and field data from fractured Monterey reservoirs in the onshore and offshore Santa Maria basin were jointly considered in estimating the solution gas-to-oil ratio of this play, to account for the possibility of multiple (pre-Monterey and Monterey) sourcing. The viability of this play (play chance) is estimated to be good; the probability that at least one undiscovered accumulation exists is predicted to be 70 percent. However, many prospects are expected to lack adequate fill (i.e., the volume of generated hydrocarbons may be insufficient to fill all traps), reservoir rocks, and/or seal. Therefore, the prospect success ratio (conditional prospect chance) is estimated to be poor; 30 percent of the prospects are predicted to be pools.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 272 MMbbl of oil and 370 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 92 pools with sizes ranging from approximately 105 Mbbl to 120 MMbbl of combined oil-equivalent resources (fig. 51). The low, mean, and high estimates of resources in the play are listed in table 16.

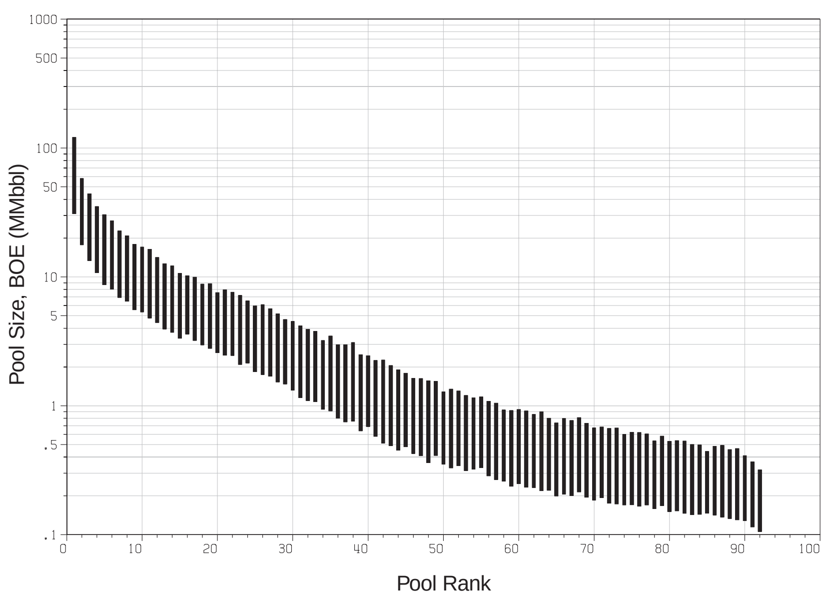


Figure 51. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Pre-Monterey Sandstone play, Bodega Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

AÑO NUEVO BASIN

by Catherine A. Dunkel

Location

The Año Nuevo basin (or "Outer Santa Cruz basin," as originally defined by Hoskins and Griffiths (1971)) is located between the Bodega and Partington basins in the Central California province (fig. 33). This elongate, northwest-trending basin extends approximately 80 miles from Monterey Bay to the Farallon Islands, is approximately 15 miles wide, and occupies an area of approximately 1,000 square miles (fig. 52). The basin is bounded on the west by the Outer Santa Cruz high and on the east by the Farallon-Pigeon Point high and the San Gregorio fault zone. A small portion of the basin lies in State waters and is exposed onshore at Point Año Nuevo.

The Año Nuevo Basin assessment area comprises only the Federal offshore portion of the basin (i.e., seaward of the 3-mile line). Water depths in the assessment area range from approximately 200 feet at the 3-mile line near Point Año Nuevo to more than 4,000 feet on the continental slope southwest of the Farallon Islands.

Geologic Setting

The Cenozoic stratigraphic succession of the Año Nuevo basin area indicates that the area has undergone a complex history of subsidence, sedimentary deposition, volcanism, uplift, and erosion (McCulloch, 1987b). The oldest rocks penetrated by offshore exploratory wells are Upper Cretaceous

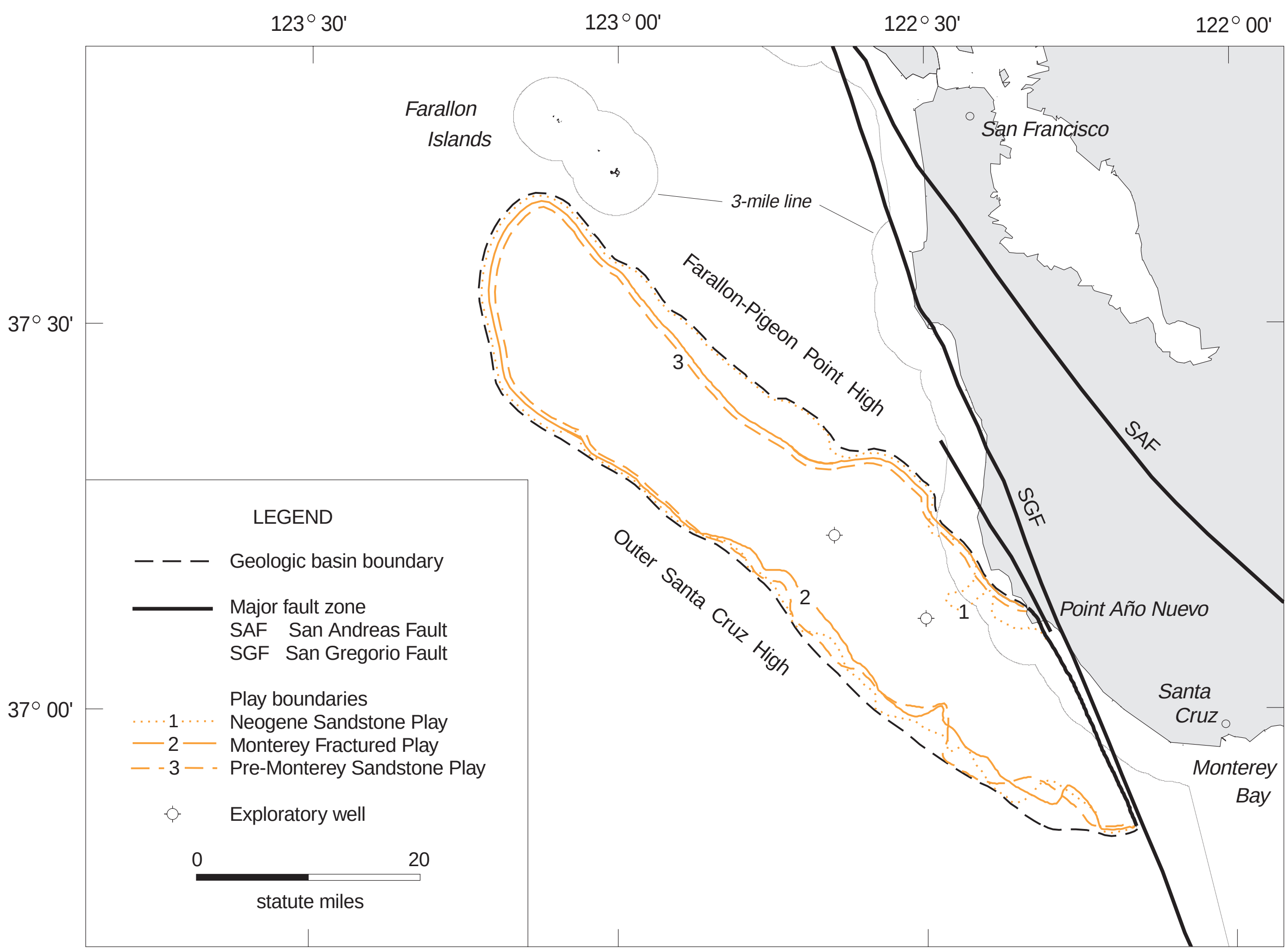
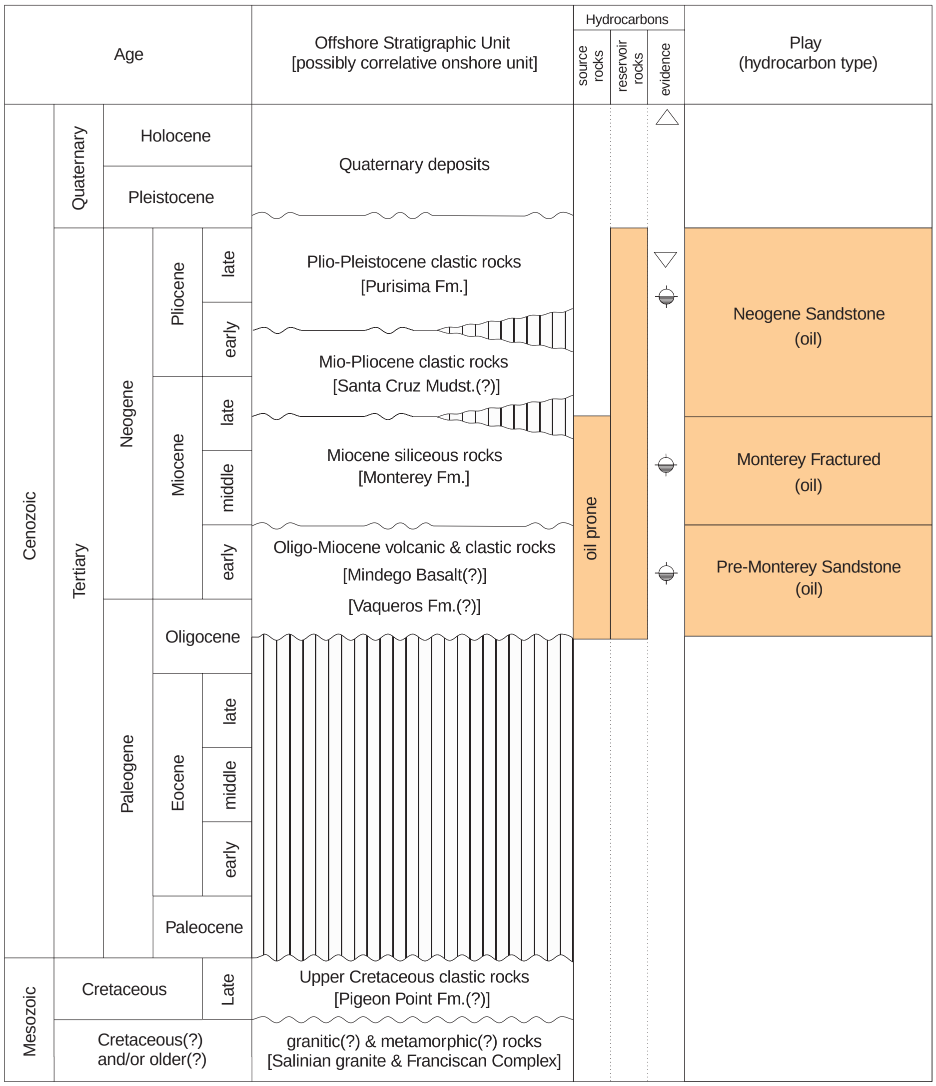


Figure 52. *Map of the Año Nuevo Basin assessment area showing petroleum geologic plays and wells.*



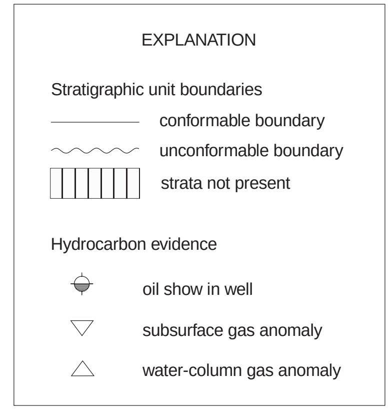


Figure 53. *Stratigraphic column of the Año Nuevo Basin assessment area showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays.*

submarine fan deposits similar (and possibly correlative[8]) to those exposed onshore at Point Año Nuevo (fig. 53). The age and character of basement rocks underlying the Upper Cretaceous strata onshore are unknown. Offshore, the Upper Cretaceous strata probably overlie Cretaceous and/or older rocks of the Salinia terrane (McCulloch, 1989), including granitic rocks (Hoskins and Griffiths, 1971) and metamorphic rocks of the Franciscan Complex (Silver and others, 1971; Mullins and Nagle, 1981); however, the spatial distribution of these dissimilar basement rocks is poorly understood. The initial subsidence and formation of the Año Nuevo basin proper may be recorded by the Upper Cretaceous strata; alternatively, these strata may be a local remnant of a larger body of Cretaceous and Paleogene strata (i.e., including strata in the Point Arena and adjacent Bodega basins) that were deposited, uplifted, and eroded prior to the formation of the basin. Following an episode of Paleogene uplift and erosion (or nondeposition of Paleocene to Oligocene strata), an episode of late Oligocene to early Miocene subsidence occurred, during which interbedded volcanic and marine clastic strata of early Miocene and possibly Oligocene age were deposited; the volcanic rocks are lithologically and temporally similar to those in other California coastal basins

[8] Strata penetrated in the offshore wells of the Año Nuevo basin were initially described by Hoskins and Griffiths (1971) and have been subsequently described by Zieglar and Cassell (1978) and McCulloch (1987b). Webster and Yenne (1987) assigned onshore formation names to the offshore strata based on lithologic and biostratigraphic (i.e., benthic foraminiferal) data from offshore well samples (fig. 53); however, given the limited number of wells and samples in the offshore Año Nuevo basin and the lack of demonstrated physical continuity between the offshore and onshore strata, these assignments and onshore-offshore correlations are uncertain. Therefore, the onshore-offshore correlations cited here and in figure 53 are considered to be possible correlations (and in some cases, possible partial correlations).

and may record a middle Tertiary extensional event that produced volcanism along the continental margin (McCulloch, 1987b). The bulk of the Año Nuevo basin fill consists of a thick sequence of middle to upper Miocene marine clastic, siliceous, and siliciclastic rocks that record a middle Miocene transgression, subsequent subsidence, and hemipelagic siliceous deposition. Some of the siliceous deposits appear to have been uplifted and eroded during the late Miocene and early Pliocene. The uneroded siliceous rocks are overlain by Pliocene and Pleistocene marine clastic rocks and semiconsolidated Quaternary marine deposits. These major Tertiary stratigraphic sequences, which were deposited in marine shelf and slope settings, are separated by boundaries that are evident on seismic-reflection profiles. The boundaries are generally unconformable along the uplifted margins of the basin and are locally unconformable at intrabasinal highs.

The structural axis and many faults and folds in the basin are predominantly northwest-trending and subparallel (or at low angles) to the San Andreas fault zone; this suggests that the origin and early deformational history of the basin may have been largely controlled by this right-lateral strike-slip fault (Wilcox and others, 1973; Blake and others, 1978). However, the variable orientation of many fold and fault trends suggests that some structural features may be genetically related to the San Gregorio fault and/or late Cenozoic compression.

Petroleum Geology

Knowledge of the petroleum geology of the basin has been garnered from two offshore exploratory wells (OCS-P 0035 #1 (south) and OCS-P 0036 #1 (north)) and a moderately dense grid of high-quality, seismic-reflection profiles across all but the northwesternmost portion of the basin; data from onshore wells and outcrops and published sources were also considered. The primary petroleum source rocks for all plays in the basin are presumed to be rocks of the Miocene Monterey Formation (fig. 53), by analogy with several California coastal basins. Although organic geochemical data are lacking for Monterey rocks in the Año Nuevo basin, the presence of organic-rich, thermally mature source rocks is strongly indicated by shows in Monterey and other strata in the basin. Structurally anomalous reflectors on seismic-reflection profiles, density contrasts on well logs, and mineralogic compositions of well samples suggest that diagenetic alteration of opal-CT-phase silica to quartz-phase silica has occurred at burial depths of approximately 4,700 feet. If the temperature required for this mineralogic conversion is coincident with the onset of oil generation in Monterey rocks (as described in the Central California province discussion), thermally mature Monterey rocks may exist over much of the basin, and two locally thick areas in the central and southeast portions of the basin may be potential oil-generation centers.

Abundant oil shows in the offshore wells and subsurface seismic amplitude anomalies (i.e., "bright spots" interpreted to be gas) indicate that oil and gas have generated and migrated within the Año Nuevo basin (fig. 53). The existence of a viable petroleum system (i.e., in which petroleum has generated, migrated, and accumulated within traps) is further confirmed by the spatial coincidence of several water-column seismic anomalies (interpreted to be gas) with the crests of subsurface structural traps. The petroleum potential of the basin may be most prospective in the southeast portion, where the San Gregorio and other vertically continuous faults may have created migration pathways through potentially generative Monterey rocks, and where numerous structural traps exist.

Plays

Three petroleum geologic plays, defined on the basis of reservoir rock stratigraphy, have been assessed in the Federal offshore portion of the basin (figs. 52 and 53). These are (1) the Neogene Sandstone play (upper Miocene and Pliocene clastic reservoirs), (2) the Monterey Fractured play (middle and upper Miocene fractured siliceous reservoirs), and (3) the Pre-Monterey Sandstone play (lower Miocene and possibly Oligocene clastic reservoirs).

Neogene sedimentary and volcanic rocks that are stratigraphically similar (and possibly correlative) to some of the strata included in these plays exist in the State offshore and onshore areas of the basin. These adjacent rocks compose the Pescadero Oil play of the Central Coastal province, which has been described and assessed by the U.S. Geological Survey (Stanley, 1995b).

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Play-specific estimates of undiscovered conventionally recoverable resources have been developed using the subjective assessment method, and these estimates have been statistically aggregated to estimate the total volume of resources in the assessment area. Select data used to develop the resource estimates are shown in appendix C.

As a result of this assessment, the total volume of undiscovered conventionally recoverable resources

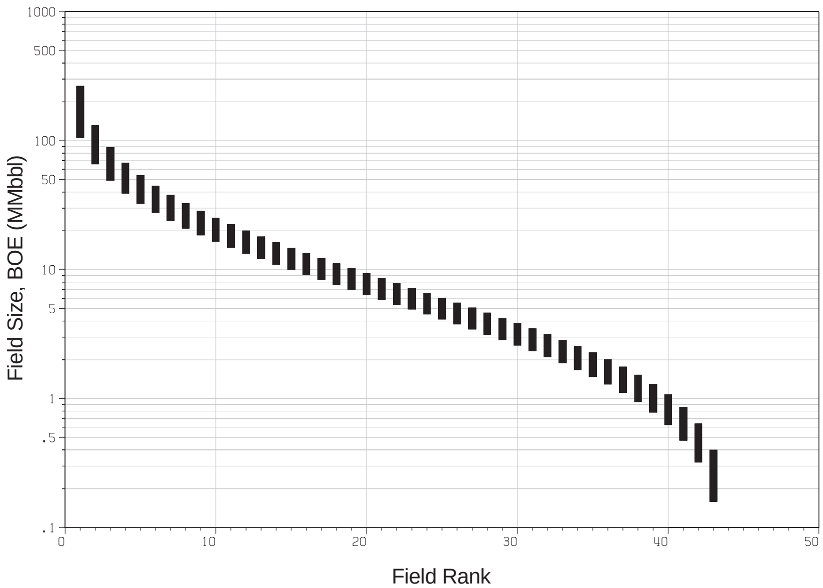


Figure 54. *Field-size rank plot of estimated undiscovered conventionally recoverable resources of the Año Nuevo Basin assessment area. Sizes of undiscovered fields are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

Table 18. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Año Nuevo Basin assessment area as of January 1, 1995, by play. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

Play	Oil (MMbbl)			Gas (Bcf)			BOE (MMbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Neogene Sandstone	0	81	184	0	95	219	0	98	222
Monterey Fractured	406	583	866	374	602	964	477	690	1,023
Pre-Monterey Sandstone	0	55	146	0	80	229	0	70	183
Total Assessment Area	*488*	*720*	*1,011*	*487*	*777*	*1,158*	*579*	*858*	*1,208*

Figure 55. *Cumulative probability plot of estimated undiscovered conventionally recoverable resources of the Año Nuevo Basin assessment area.*

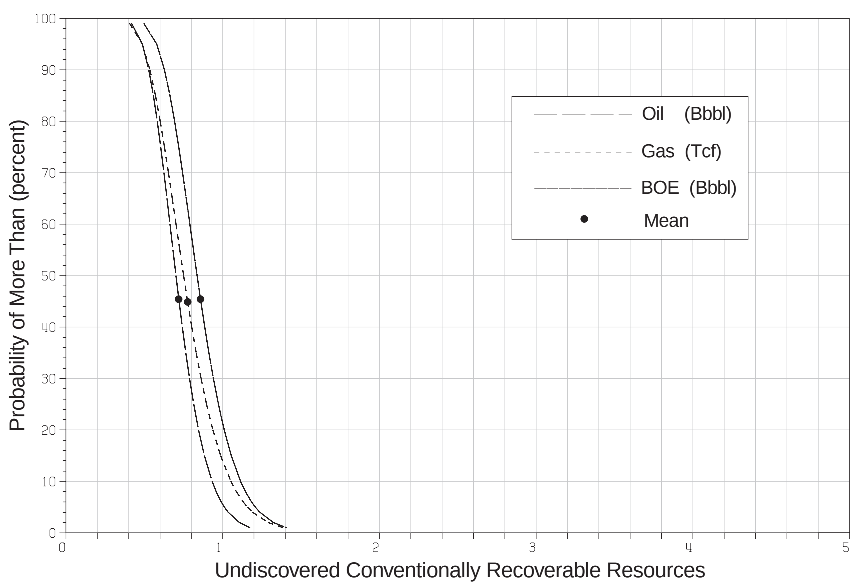


Table 19. *Estimates of undiscovered economically recoverable oil and gas resources in the Año Nuevo Basin assessment area as of January 1, 1995, by economic scenario. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $25-per-barrel scenario is based on prices of $25 per bbl of oil and $2.94 per Mcf of gas; the $50-per-barrel scenario is based on prices of $50 per barrel of oil and $5.87 per Mcf of gas.*

Economic Scenario	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)
$18 per barrel	475	512	566
$25 per barrel	545	588	650
$50 per barrel	632	682	754

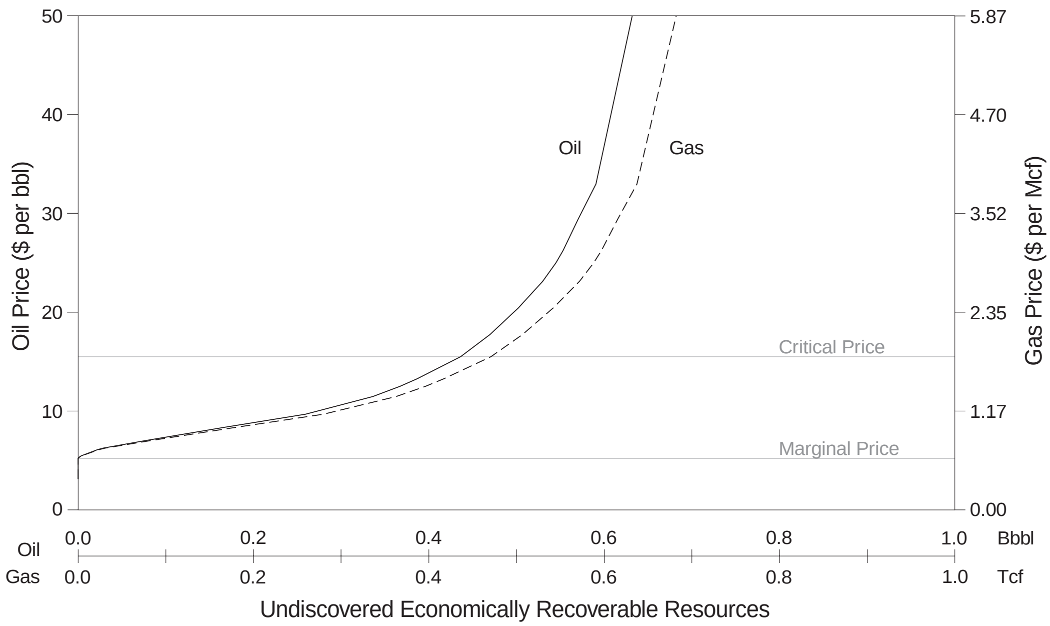


Figure 56. *Price-supply plot of estimated undiscovered economically recoverable resources of the Año Nuevo Basin assessment area.*

in the Año Nuevo Basin assessment area is estimated to be 720 MMbbl of oil and 777 Bcf of associated gas (mean estimates). This volume may exist in 43 fields with sizes ranging from approximately 160 Mbbl to 265 MMbbl of combined oil-equivalent resources (fig. 54). The majority of these resources (approximately 80 percent on a combined oil-equivalence basis) are estimated to exist in the Monterey Fractured play. The low, mean, and high estimates of resources in the assessment area are listed in table 18 and illustrated in figure 55.

Undiscovered Economically Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the assessment area that may be economically recoverable under various economic scenarios have been developed using the economic assessment method. Select data used to develop the resource estimates are shown in appendix D.

As a result of this assessment, 475 MMbbl of oil and 512 Bcf of associated gas are estimated to be economically recoverable from the Año Nuevo Basin assessment area under economic conditions existing as of this assessment (i.e., the $18-per-barrel economic scenario) (table 19). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions (fig. 56).

Total Resource Endowment

No accumulations of resources have been discovered in the assessment area. Therefore, the aforementioned estimates of undiscovered conventionally recoverable resources compose the estimated total resource endowment of the area.

ACKNOWLEDGMENTS

The author thanks Richard Stanley and James Crouch for sharing information and insight regarding the geology and petroleum potential of the central California coastal area and the Año Nuevo basin, James Cummings and Richard Hazen for assisting in preparing maps, Scott Drewry for preparing figures, and Margaret Kimbell-Drewry for initial data compilation.

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NEOGENE SANDSTONE PLAY

PLAY DEFINITION

The Neogene Sandstone play of the Año Nuevo Basin assessment area is defined to include accumulations of oil and associated gas in upper Miocene and Pliocene clastic rocks overlying the Monterey Formation. This basin-wide play encompasses an area of approximately 900 square miles (fig. 52) and exists at burial depths of approximately 1,000 to 3,000 feet.

PETROLEUM GEOLOGIC CHARACTERISTICS

Potential petroleum source rocks for the play are oil-prone Monterey rocks (fig. 53), which may be thermally mature throughout the basin; two areas in the central and southeast portions of the basin may be potential oil-generation centers. The oil is expected to be heavy (15 to 20 °API) and high in sulfur, by analogy with Monterey-sourced oils produced from several California coastal basins. Speculatively, reservoirs in this play may contain a greater proportion of gas due to selective upward migration of free associated gas from underlying generative Monterey rocks. No other potential source rocks are presumed to exist for this play.

Potential reservoir rocks consist of upper Miocene to lower Pliocene sandstones and siltstones (possibly correlative in part to the Santa Cruz Mudstone) and lower to upper Pliocene sandstones and siltstones (possibly correlative in part to the Purisima Formation) (fig. 53). Core and log analyses indicate that the rocks have fair to good reservoir quality.

Migration of oil and associated gas from underlying generative Monterey rocks is presumed to have occurred along fractures, faults, and unconformities.

Structural and stratigraphic traps are expected to exist in the play. Potential structural traps include anticlines, fault truncations, and faulted anticlines; although some of these have been mapped with seismic profiles, much of the post-Monterey section is relatively undeformed and lacks abundant and complex structural traps. Stratigraphic traps may exist at pinchouts of sandstone interbeds and where sandstones wedge out along the Outer Santa Cruz and Farallon-Pigeon Point highs. Seals may be provided by faults and unconformities and by Pliocene and Pleistocene mudstones and shales.

EXPLORATION

Two exploratory wells have penetrated the Federal offshore portion of this frontier play. No visible shows of oil were observed; however, a solvent show of oil was encountered in one well (OCS-P 0036 #1). Additionally, the presence of gas is strongly suggested by a well-imaged seismic amplitude anomaly (bright spot) in the southern part of the play.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective

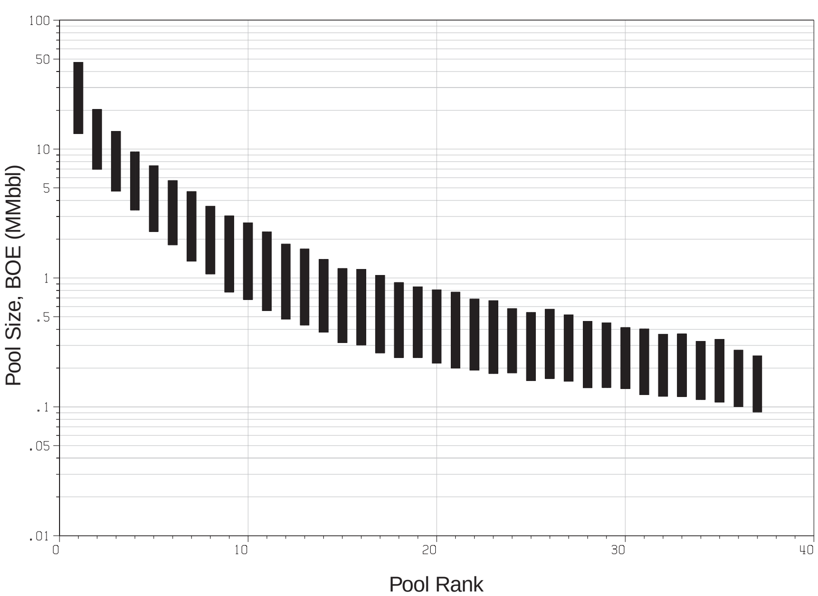


Figure 57. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Neogene Sandstone play, Año Nuevo Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

assessment method. Select data used to develop the resource estimates are shown in appendix C.

Structural information from seismic profiles and stratigraphic information from the exploratory wells were used to estimate the volume and number of pools. The oil recovery factor (oil yield) was estimated by analogy with several producing fields in the Pico-Repetto Sandstone play of the Santa Barbara-Ventura basin; the solution gas-to-oil ratio was estimated by analogy with select Monterey-producing fields in the onshore and offshore portions of the Santa Maria basin. The viability of this play (play chance) is estimated to be excellent; the probability that at least one undiscovered accumulation exists is predicted to be 95 percent. However, many prospects are expected to lack adequate fill (i.e., the volume of generated hydrocarbons may be insufficient to fill all traps), reservoir rocks, and/or seal. Therefore, the prospect success ratio (conditional prospect chance) is estimated to be poor; only 30 percent of the prospects are predicted to be pools.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 81 MMbbl of oil and 95 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 37 pools with sizes ranging from approximately 90 Mbbl to 50 MMbbl of combined oil-equivalent resources (fig. 57). The low, mean, and high estimates of resources in the play are listed in table 18.

MONTEREY FRACTURED PLAY

PLAY DEFINITION

The Monterey Fractured play of the Año Nuevo Basin assessment area is defined to include accumulations of oil and associated gas in middle and upper Miocene fractured siliceous rocks of the Monterey Formation. This basin-wide play encompasses an area of approximately 800 square miles (fig. 52) and exists at burial depths of approximately 3,000 to 6,000 feet.

PETROLEUM GEOLOGIC CHARACTERISTICS

Potential petroleum source rocks for the play are oil-prone Monterey rocks (fig. 53), which may be thermally mature throughout the basin; two areas in the central and southeast portions of the basin may be potential oil-generation centers. The oil is expected to be heavy (15 to 20 °API) and high in sulfur, by analogy with Monterey-sourced oils produced from several California coastal basins. Speculatively, reservoirs in the upper portion of this play may contain lighter, gas-enriched oil due to selective upward migration of higher-viscosity oil and free associated gas.

Potential reservoir rocks consist of middle to upper Miocene fractured siliceous shales and cherts of the Monterey Formation (fig. 53). Mineralogic compositions of well samples indicate that the original biogenic (opal-A) silica in these rocks has been diagenetically altered to opal-CT and quartz. Core and log analyses indicate that the rocks have good to excellent reservoir quality, and that the best potential reservoir rocks may exist below the opal-CT-to-quartz diagenetic boundary, where fracture density and porosity may be enhanced. Multidirectional migration of oil and associated gas from in situ generative Monterey rocks is presumed to have occurred along fractures and faults, some of which breach the diagenetic boundary.

Predominantly structural traps are expected to exist in the play and to include anticlines, fault truncations, and simple to complexly faulted anticlines. Several potential structural traps have been mapped with seismic profiles; the majority of these exist within a northwest-trending zone along the eastern margin of the basin. Speculatively, some stratigraphic traps formed by pinchouts of siliciclastic interbeds may exist in the play. Seals may be provided by fractures, faults, and unconformities; by an inferred “tar accumulation zone” at the diagenetic boundary; and by mudstones and shales of the overlying Pliocene section.

EXPLORATION

Two exploratory wells have penetrated the Federal offshore portion of this frontier play. Abundant shows of free tarry oil, tar stains on fractures, and pieces of viscous and dry tar were encountered throughout the Monterey section in both wells.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

Structural information from seismic profiles and stratigraphic information from the exploratory wells were used to estimate the volume and number of pools. The oil recovery factor (oil yield) and solution gas-to-oil ratio were estimated by analogy with select Monterey-producing fields in the Federal

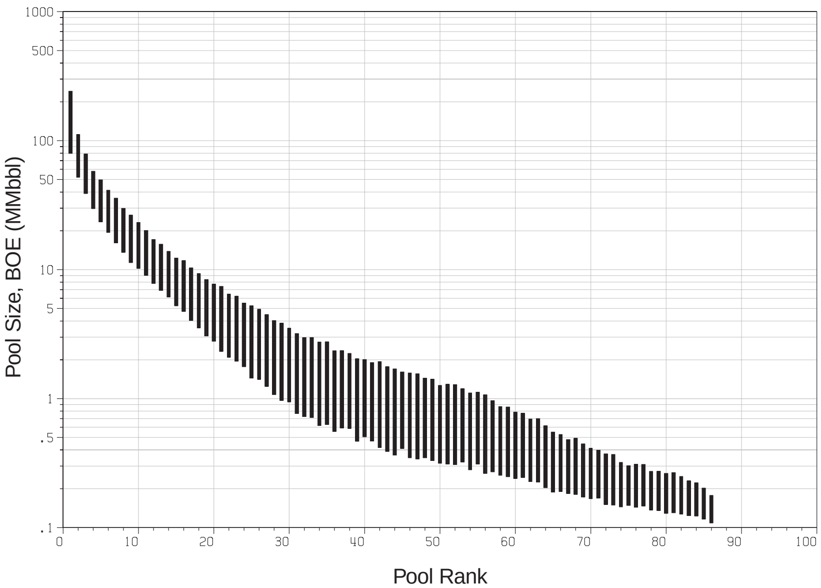


Figure 58. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Monterey Fractured play, Año Nuevo Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

offshore portion of the Santa Maria and Santa Barbara-Ventura basins. The viability of this play (play chance) is estimated to be assured; the probability that at least one undiscovered accumulation exists is predicted to be 100 percent. However, some prospects are expected to lack adequate fill (i.e., the volume of generated hydrocarbons may be insufficient to fill all traps), reservoir rocks, and/or seal. Therefore, the prospect success ratio (conditional prospect chance) is estimated to be good; 60 percent of the prospects are predicted to be pools.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 583 MMbbl of oil and 602 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 86 pools with sizes ranging from approximately 110 Mbbl to 245 MMbbl of combined oil-equivalent resources (fig. 58). The low, mean, and high estimates of resources in the play are listed in table 18.

PRE-MONTEREY SANDSTONE PLAY

PLAY DEFINITION

The Pre-Monterey Sandstone play of the Año Nuevo Basin assessment area is defined to include accumulations of oil and associated gas in lower Miocene and possibly Oligocene clastic rocks underlying the Monterey Formation. This basin-wide play encompasses an area of approximately 800 square miles (fig. 52) and exists at burial depths of approximately 5,000 to 8,000 feet.

PETROLEUM GEOLOGIC CHARACTERISTICS

The primary potential petroleum source rocks for the play are oil-prone Monterey rocks (fig. 53), which may be thermally mature throughout the basin; two areas in the central and southeast portions of the basin may be potential oil-generation centers. The oil is expected to be heavy (15 to 20 °API) and high in sulfur, by analogy with Monterey-sourced oils produced from several California coastal basins. Other potential source rocks may exist in pre-Monterey clastic rocks of this play; however, the generative potential of these in situ source rocks is considered less prospective than the overlying Monterey rocks. Oil from pre-Monterey rocks, if generated, is expected to have higher gravity (25 to 45 °API), lower sulfur content, and a greater proportion of dissolved gas, based on analogy with Paleogene-sourced oils produced from the Santa Barbara-Ventura and onshore La Honda basins.

Potential reservoir rocks consist of lower Miocene and possibly Oligocene sandstones and siltstones (possibly correlative in part to the Mindego Basalt and Vaqueros Formation) (fig. 53). Core and log analyses suggest that these rocks may have fair reservoir quality, but that porosity and permeability may be diminished by the presence of volcaniclastic clays, compaction, and cementation. Migration of oil and associated gas from overlying generative

Monterey rocks (and generative pre-Monterey rocks, if they exist) is presumed to have occurred along fractures, faults, and unconformities.

Structural and stratigraphic traps are expected to exist in the play. Potential structural traps include anticlines, fault truncations, and simple to complexly faulted anticlines. Several potential structural traps have been mapped with seismic profiles; the majority of these exist within a northwest-trending zone along the eastern margin of the basin. Stratigraphic traps may exist at pinchouts of sandstone interbeds and where sandstones wedge out along the Outer Santa Cruz and Farallon-Pigeon Point highs. Seals may be provided by faults and unconformities, volcanic rocks and shales of this play, and siliceous shales and cherts of the overlying Miocene and Pliocene sections.

Exploration

Two exploratory wells have penetrated the Federal offshore portion of this frontier play. Visible oil shows were observed in one well (OCS-P 0035 #1) and some solvent shows were observed in the other well (OCS-P 0036 #1).

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

Structural information from seismic profiles and stratigraphic information from the exploratory wells were used to estimate the volume and number of pools. The oil recovery factor (oil yield) was estimated by analogy with select producing fields in the Sespe-Alegria-Vaqueros Sandstone play in the Santa Barbara-Ventura basin. This analog data set and field data from fractured Monterey reservoirs in the onshore and offshore Santa Maria basin were jointly considered in estimating the solution gas-to-oil ratio of this play, to account for the possibility of multiple (pre-Monterey and Monterey) sourcing. The viability of this play (play chance) is estimated to be good; the probability that at least one undiscovered accumulation exists is predicted to be 60 percent. However, many prospects are expected to lack adequate fill (i.e., the volume of generated hydrocarbons may be insufficient to fill all traps), reservoir rocks, and/or seal. Therefore, the prospect success ratio (conditional prospect chance) is estimated to be poor; 30 percent of the prospects are predicted to be pools.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 55 MMbbl of oil and 80 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 54 pools with sizes ranging from approximately 50 Mbbl to 40 MMbbl of combined oil-equivalent resources (fig. 59). The low, mean, and high estimates of resources in the play are listed in table 18.

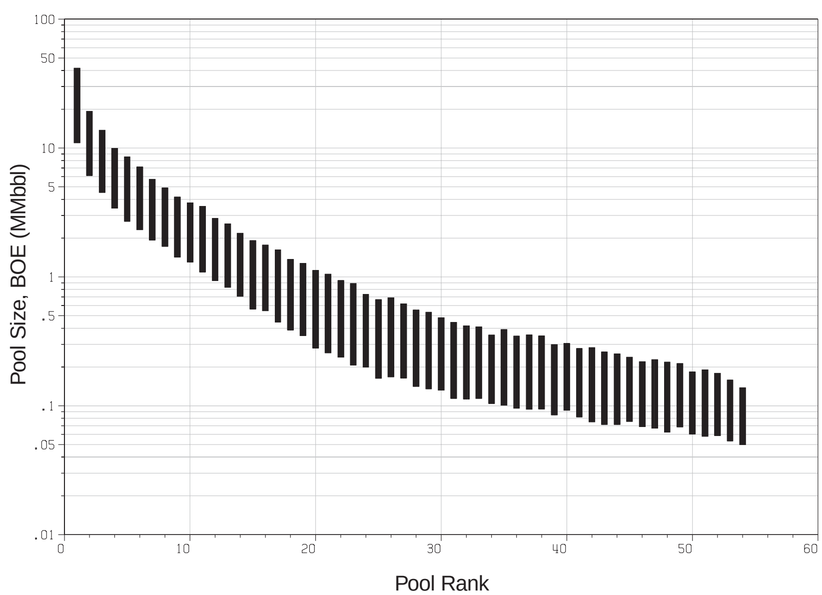


Figure 59. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Pre-Monterey Sandstone play, Año Nuevo Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

SANTA MARIA-PARTINGTON BASIN

by Drew Mayerson

Location

The Santa Maria basin and the Partington basin (or "Sur Basin," as described by McCulloch (1987b)) are the southernmost assessed basins in the Central California province (fig. 33). Both are northwest-trending basins with fault-bounded eastern limits and structural highs on the north and south.

The Santa Maria basin proper is informally subdivided along the Hosgri fault zone into onshore and offshore subareas (fig. 60). The offshore Santa Maria basin is bounded on the west by the Santa Lucia Bank fault as far north as approximately Point Piedras Blancas. North of that point, a northeast-trending structural discontinuity (referred to as the "San Martin structural discontinuity" by McCulloch (1987b)) separates west-dipping, highly deformed basement strata of the offshore Santa Maria basin from lesser-deformed, east-dipping basement strata of the Partington basin. The northeast-trending "Amberjack high" forms the boundary between the offshore Santa Maria basin and the Santa Barbara-Ventura basin. The offshore Santa Maria basin is approximately 100 miles long and 25 miles wide, and occupies an area of approximately 2,500 square miles. Water depths range from 300 feet near Point Sal to 3,500 feet in the southwest part of the basin.

The northern boundary of the Partington basin is defined by the structurally high Sur platform offshore Point Sur. Exposed basement strata define the western limit of the basin; to the east, the basin is bounded by the Hosgri fault zone. The Partington basin is

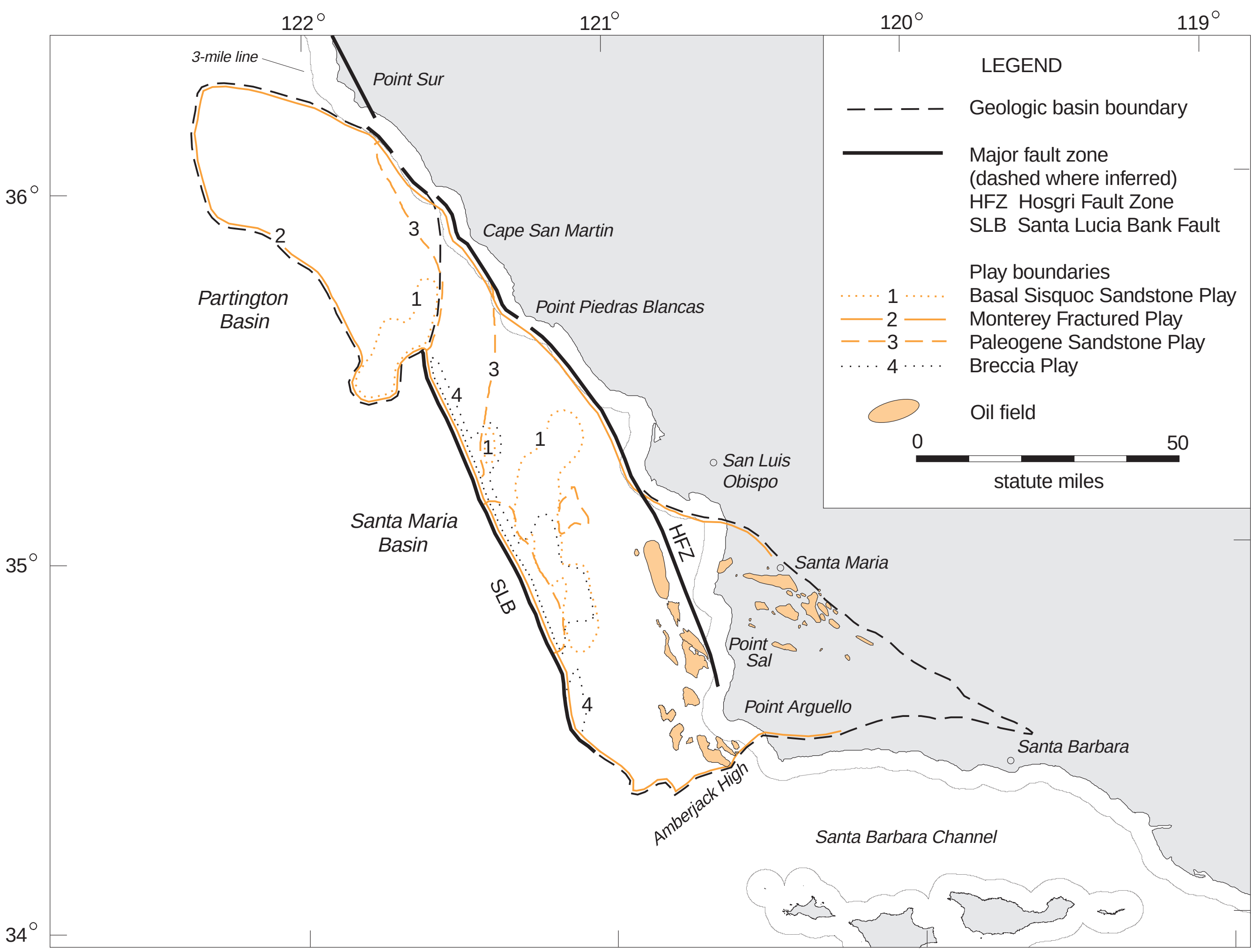


Figure 60. *Map of the Santa Maria-Partington Basin assessment area showing petroleum geologic plays and fields.*

approximately 25 miles wide and 65 miles long and encompasses an area of approximately 1,300 square miles. Water depths range from 500 to 8,000 feet.

For the purpose of this assessment, the Federal offshore portions of the Santa Maria and Partington basins have been combined into a single assessment area based on the interbasinal continuity of Neogene strata. The composite Santa Maria-Partington Basin assessment area is approximately 165 miles long and 25 mile wide and occupies an area of approximately 3,800 square miles. Water depths range from 300 feet near Point Sal to 8,000 feet in the northwest part of the assessment area.

Geologic Setting

Regional extension during the early Miocene caused the rapid subsidence of the Santa Maria basin. Offshore seismic-reflection profiles depict westward-tilted, normal-faulted, basement blocks that formed Miocene and Pliocene subbasins that are filled with volcanic rocks and biogenic and clastic sediments. Uplift and structural inversion of the basin began in the early Pliocene, resulting in reactivation of the normal faults and folding of Miocene and Pliocene strata into anticlines that are the traps for much of the oil in the basin today.

The Partington basin appears to have undergone a somewhat different tectonic history. In contrast to the complex folding in the offshore Santa Maria basin, Partington basin strata have been only minimally deformed. Basement topography dips uniformly east-northeast and terminates against or is thrust under the Hosgri fault zone.

More than 50 exploratory wells have been drilled in the southern and central portions of the offshore Santa Maria basin; the northern portion of the basin and all of the Partington basin remain undrilled. Most exploratory wells bottomed in Jurassic rocks of the Franciscan Complex; however, some wells bottomed in rocks of Cretaceous age or never reached basement; at least one well encountered Jurassic ophiolite. Similar basement rocks probably exist in the northern portion of the Santa Maria basin and in the Partington basin.

Paleogene rocks are missing in most of the wells and are presumed to be absent throughout most of the offshore Santa Maria basin. However, recent interpretation of seismic profiles indicates that a large body of strata—possibly a remnant of Paleogene age—exists along the Santa Lucia Bank fault and extends northward into the Partington basin. The strata have a maximum thickness in excess of 10,000 feet.

Neogene strata of the Lospe, Point Sal, Monterey, Sisquoc, Foxen, and Careaga Formations overlie basement rocks in the offshore Santa Maria and Partington basins (fig. 61). Lower to middle Miocene volcanics are also present throughout much of the offshore Santa Maria basin. The total thickness of these Neogene strata exceeds 10,000 feet in the depocenters and thins to 2,000 feet over the numerous intrabasinal uplifts in the offshore Santa Maria basin. Near Point Piedras Blancas, erosion and nondeposition have thinned the Neogene stratigraphic section to less than 1,000 feet. In many areas, the Monterey and underlying formations have been entirely eroded, leaving a thin shell of Sisquoc Formation in direct contact with basement rocks.

Exploration and Discovery Status

The first exploratory well (OCS-P 0060 #1) in the offshore Santa Maria basin was drilled in 1964 about 15 miles northwest of Point Sal. Although the well had abundant shows of oil in the Monterey Formation, it was not tested. However, the Monterey Formation has been the primary exploration target in the basin since the discovery well (OCS-P 0316 #1) at the Point Arguello field was drilled in 1980; the well was drilled as a result of OCS Lease Sale 48, which was held in 1979. Three subsequent lease sales that included the offshore Santa Maria basin have been held (Sale 53 in 1981, Sale RS-2 in 1982, and Sale 73 in 1983). As a result of those sales, 78 OCS blocks have been leased, more than 50 exploratory wells have been drilled, and 12 additional fields have been discovered. Two of the thirteen fields in the offshore Santa Maria basin (Point Arguello and Point Pedernales fields) were in production as of this assessment.

Seismic-reflection data coverage in the offshore Santa Maria and Partington basins is dense; the average trackline spacing in southern and central offshore Santa Maria basin is less than one-half mile. Toward the west and north into Partington basin, the coverage thins to approximately 1-mile spacing. For this assessment, a seismic data set of multiple surveys with a grid density of approximately 1-mile spacing was interpreted.

Plays

Four petroleum geologic plays, defined on the basis of reservoir rock stratigraphy, have been assessed in the Santa Maria-Partington Basin assessment area (fig. 61). These include two plays from which petroleum production has been established in the Santa Maria basin: the Basal Sisquoc Sandstone play, which is established only onshore and is considered frontier offshore, and the Monterey Fractured play,

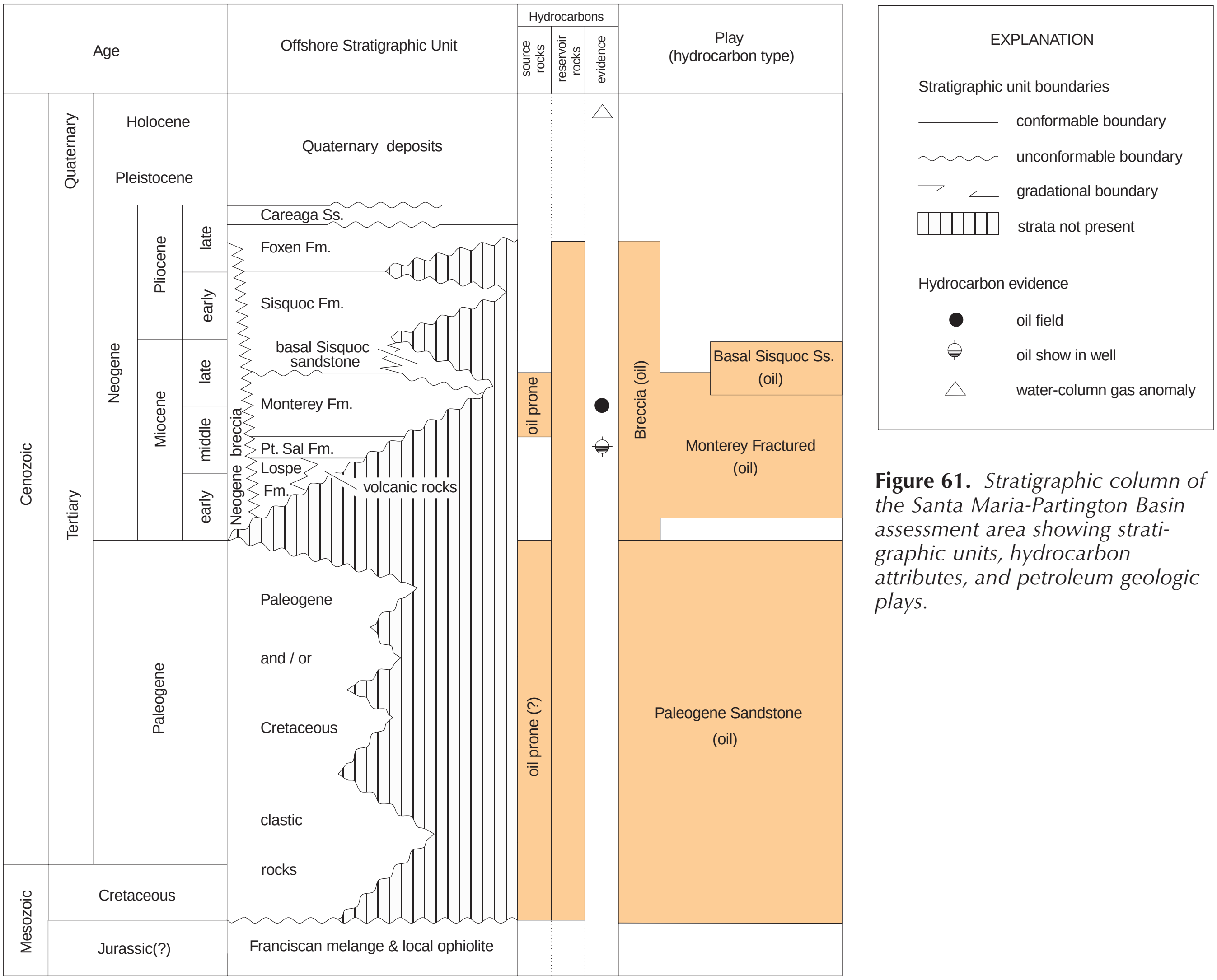


Figure 61. *Stratigraphic column of the Santa Maria-Partington Basin assessment area showing stratigraphic units, hydrocarbon attributes, and petroleum geologic plays.*

which is established offshore and onshore. Additionally, two conceptual plays have been assessed. The Paleogene Sandstone play is defined by seismic character and the presence of a thick section of continuous reflectors below the Monterey Formation in the Partington basin and in the outer portion of the offshore Santa Maria basin. The Breccia play is defined by proximity to large expanses of uplifted and eroded basement; accumulations in this play are presumed to be similar to breccia reservoirs in the onshore Los Angeles basin.

The primary petroleum source rocks for three of these four plays are organic-rich shales and phosphatic rocks of the Monterey Formation. Although Monterey rocks may be a source for the Paleogene Sandstone play where the two units are juxtaposed, the extreme thickness of the Paleogene(?) section in the Partington basin necessitates an additional source to charge Paleogene reservoirs in that basin. Therefore, a Paleogene source analogous to Paleogene strata in the Santa Barbara-Ventura basin is assumed to exist in the offshore Santa Maria and Partington basins.

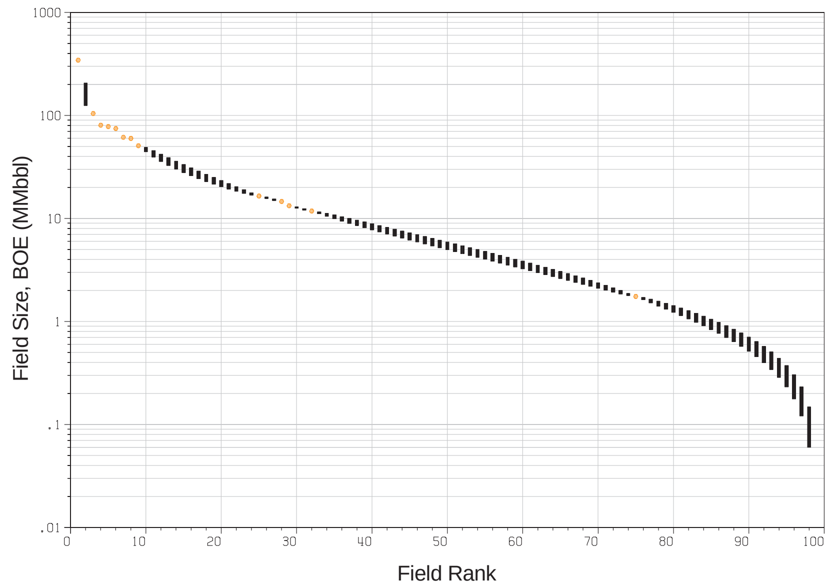
Mesozoic and Tertiary clastic and siliceous rocks, some of which are stratigraphically similar (and partly correlative) to the strata included in these plays, exist in the State offshore and onshore areas of the Santa Maria basin and in the State offshore area of the Partington basin. These adjacent rocks compose the Anticlinal Trends, Basin Margin, and Diagenetic plays of the Santa Maria Basin province, which has been described and assessed by the U.S. Geological Survey (Tennyson, 1995).

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Play-specific estimates of undiscovered conventionally recoverable resources have been developed using the subjective assessment and discovery

Figure 62. *Field-size rank plot of estimated conventionally recoverable resources of the Santa Maria-Partington Basin assessment area. Sizes of discovered fields are shown by dots. Sizes of undiscovered fields are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile value of a probability distribution, respectively.*



assessment methods, and these estimates have been statistically aggregated to estimate the total volume of resources in the assessment area. Select data used to develop the resource estimates are shown in appendix C.

As a result of this assessment, the total volume of undiscovered conventionally recoverable resources in the Santa Maria-Partington Basin assessment area is estimated to be 782 MMbbl of oil and 738 Bcf of associated gas (mean estimates). This volume may exist in 85 fields with sizes ranging from approximately 60 Mbbl to 205 MMbbl of combined oil-equivalent resources (fig. 62). The majority of these resources (approximately 88 percent on a combined oil-equivalence basis) are estimated to exist in the Monterey Fractured play. The low, mean, and high estimates of resources in the assessment area are listed in table 20 and illustrated in figure 63.

Undiscovered Economically Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the assessment area that may be economically recoverable under various economic scenarios have been developed using the economic assessment method. Select data used to develop the resource estimates are shown in appendix D.

As a result of this assessment, 189 MMbbl of oil and 178 Bcf of associated gas are estimated to be economically recoverable from the Santa Maria-Partington Basin assessment area under economic conditions existing as of this assessment (i.e., the $18-per-barrel economic scenario) (table 21). Larger volumes of resources are expected to be economically recoverable under increasingly favorable economic conditions (fig. 64).

Table 20. *Estimates of undiscovered conventionally recoverable oil and gas resources in the Santa Maria-Partington Basin assessment area as of January 1, 1995, by play. All estimates are risked values. The low, mean, and high estimates correspond to the 95th-percentile, mean, and 5th-percentile values of a probability distribution, respectively. Percentile values are not additive; some total mean values may not equal the sum of the component values due to independent rounding.*

Play	Oil (MMbbl)			Gas (Bcf)			BOE (MMbbl)		
	Low	Mean	High	Low	Mean	High	Low	Mean	High
Basal Sisquoc Sandstone	47	80	140	45	80	140	56	94	163
Monterey Fractured	629	687	787	561	629	752	729	799	921
Paleogene Sandstone	0	7	36	0	21	141	0	10	60
Breccia	0	8	56	0	8	61	0	10	67
Total Assessment Area	*678*	*782*	*895*	*598*	*738*	*897*	*787*	*913*	*1,051*

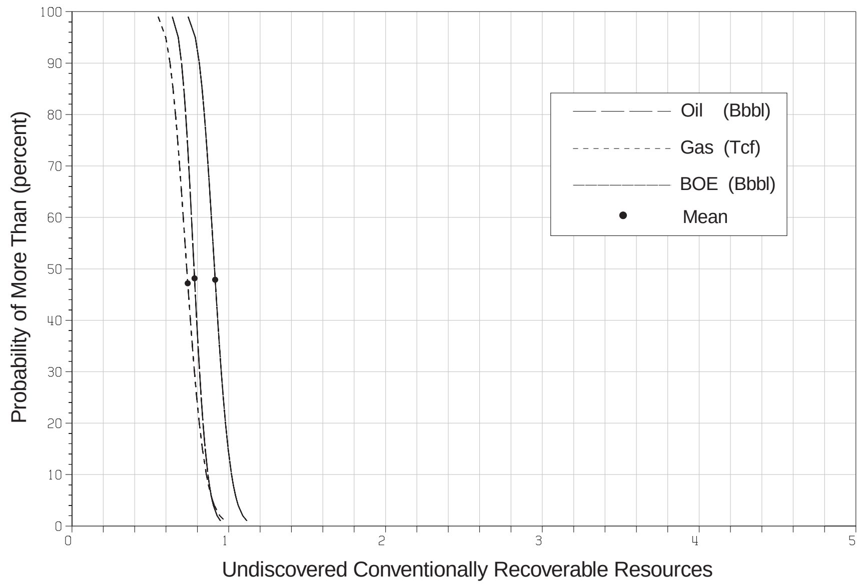


Figure 63. *Cumulative probability plot of estimated undiscovered conventionally recoverable resources of the Santa Maria-Partington Basin assessment area.*

Table 21. *Estimates of undiscovered economically recoverable oil and gas resources in the Santa Maria-Partington Basin assessment area as of January 1, 1995, by economic scenario. All estimates are risked mean values. The $18-per-barrel scenario is based on prices of $18 per bbl of oil and $2.11 per Mcf of gas; the $25-per-barrel scenario is based on prices of $25 per bbl of oil and $2.94 per Mcf of gas; the $50-per-barrel scenario is based on prices of $50 per barrel of oil and $5.87 per Mcf of gas.*

Economic Scenario	Oil (MMbbl)	Gas (Bcf)	BOE (MMbbl)
$18 per barrel	189	178	220
$25 per barrel	275	259	321
$50 per barrel	497	469	581

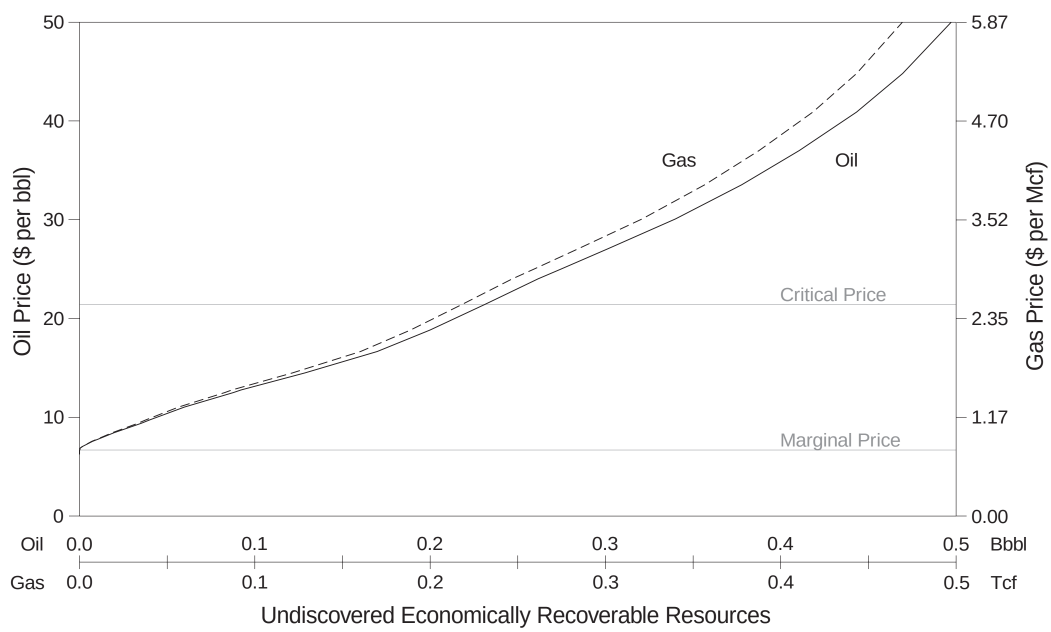


Figure 64. *Price-supply plot of estimated undiscovered economically recoverable resources of the Santa Maria-Partington Basin assessment area.*

Total Resource Endowment

As of this assessment, cumulative production from the assessment area was 118 MMbbl of oil and 43 Bcf of gas; remaining reserves were estimated to be 667 MMbbl of oil and 659 Bcf of gas. These discovered resources (all of which are from the Monterey Fractured play) and the aforementioned undiscovered conventionally recoverable resources collectively compose the area's estimated total resource endowment of 1.57 Bbbl of oil and 1.44 Tcf of gas (table 22).

Acknowledgments

The author gratefully acknowledges James K. Crouch and Marilyn Tennyson for providing their ideas and insights into the assessment of the Santa Maria basin. Special thanks go to William Kou for researching many of the analogs used for this assessment and spending countless hours at the computer helping to model the distributions. I would also like to extend thanks to Dale Julander, Ron Heck, Ed Edwards, and Chris Sorlien for their review of the play concepts and providing valuable input into this assessment. Finally, this author would like to acknowledge Cathie Dunkel for her unbridled enthusiasm and guidance on this project, her valuable input into the analog analysis for many of the plays, and her excellent editorial skills.

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Hoskins and Griffiths, 1971
Isaacs, 1984
McCulloch, 1989
McLean and Wiley, 1987
Webster and others, 1988
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Table 22. *Estimates of the total endowment of oil and gas resources in the Santa Maria-Partington Basin assessment area. Estimates of discovered resources (including cumulative production and remaining reserves) and undiscovered resources are as of January 1, 1995. Estimates of undiscovered conventionally recoverable resources are risked mean values. Some total values may not equal the sum of the component values due to independent rounding.*

Resource Category	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Cumulative Production	0.12	0.04	0.13
Remaining Reserves	0.67	0.66	0.78
Undiscovered Conventionally Recoverable Resources	0.78	0.74	0.91
Total Resource Endowment	*1.57*	*1.44*	*1.82*

Basal Sisquoc Sandstone Play

Play Definition

The Basal Sisquoc Sandstone play of the Santa Maria-Partington Basin assessment area is defined to include stratigraphic and structural accumulations of oil and associated gas in Pliocene clastic sediments at the base of the Sisquoc Formation. This play is established (i.e., proven to exist) in the onshore Santa Maria basin where Monterey Formation strata have been uplifted and eroded around the basin margin and redeposited as coarse clastic sediments atop the Monterey Formation (e.g., Thomas and Brooks Sands in the Cat Canyon field, Basal Sisquoc Sand in the Guadalupe field). In the offshore Santa Maria basin, this play has not been tested. This play occurs in both the offshore Santa Maria and Partington basins where the Monterey has been uplifted, eroded, and redeposited on the flanks of the uplift. The interbasinal play covers an area of approximately 450 square miles and occurs at burial depths generally less than 3,000 feet (fig. 60).

Petroleum Geologic Characteristics

Potential petroleum source rocks for the play are oil-prone, middle to upper Miocene Monterey rocks stratigraphically below the Sisquoc Formation. Maximum Monterey thickness exceeds 2,000 feet in the basins; however, in areas where this play is present, the Monterey has been eroded and may be significantly less than 1,000 feet thick. Additionally, Monterey rocks within the area of this play may not be thermally mature unless they have been buried to depths greater than about 3,000 feet. Monterey rocks buried in synclines adjacent to the play are probably thermally mature and fractures may provide pathways for migration of petroleum into the play area. A similar situation exists in the onshore Santa Maria basin where petroleum has migrated several miles from the Santa Maria Valley syncline into stratigraphic traps in the Santa Maria Valley field.

Potential reservoir rocks include Pliocene sandstones that are composed of sediments shed from uplifted and eroded Monterey and older strata. Analysis of similar strata in traps of the Cat Canyon, Guadalupe, and Santa Maria Valley fields indicates that the strata have net thicknesses from 45 to 600 feet, porosities from 10 to 40 percent, and permeabilities from 200 to 3,350 millidarcies.

Traps in this play are generally stratigraphic; but the potential for structural accumulations cannot be discarded. Two areas of potential structural and stratigraphic traps have been mapped with seismic data. The largest of the two is located atop a large uplift that extends northward from near the western margin of the central offshore Santa Maria basin to the northern area of the basin approximately 15 miles west of Point Estero. The second area is located atop a northeast-trending uplift 15 to 20 miles west of Point Piedras Blancas in the Partington basin. In both areas, the Monterey has been partially or completely eroded, and detrital material has been shed down the flanks of the uplift and possibly accumulated in contact with Monterey strata below. Seals may be provided by mudstones and shales within the Sisquoc or younger formations, but may not be effective because the strata are generally thin.

EXPLORATION

No offshore wells have tested this conceptual play. In the onshore Santa Maria basin, petroleum is produced from basal Sisquoc sandstones in several areas (e.g., East and Sisquoc areas of the Cat Canyon field; Guadalupe field; and Clark, Bradley, and Southeast areas of the Santa Maria Valley field). Although seismic data have been used to delineate this play in the offshore, no bright spots or other hydrocarbon indicators have been observed on the interpreted seismic profiles.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

Volumetric parameters for the play (i.e., pool area, net-pay thickness, and oil recovery factor) were estimated from onshore Santa Maria basin field analogs. Areas of likely traps were identified using the seismic data, but individual trap outlines were not mapped. The number of pools in the play was estimated by areal comparison to the onshore Santa Maria basin. The solution gas-to-oil ratio was estimated using Monterey Formation ratios from the offshore Santa Maria basin.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 80 MMbbl of oil and 80 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in 15 pools with sizes ranging from approximately 235 Mbbl to 35 MMbbl of combined oil-equivalent resources (fig. 65). The low, mean, and high estimates of resources in the play are listed in table 20.

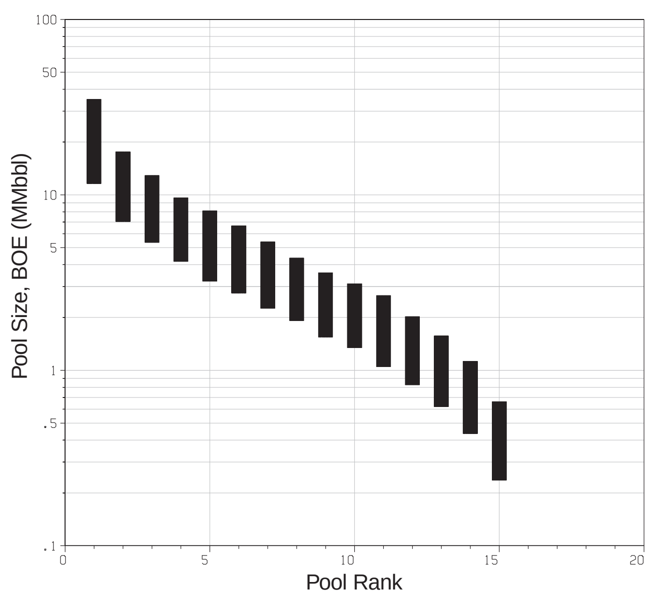

Figure 65. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Basal Sisquoc Sandstone play, Santa Maria-Partington Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

Monterey Fractured Play

Play Definition

The Monterey Fractured play of the Santa Maria-Partington Basin assessment area is an established play that includes oil and associated gas accumulations in fractured siliceous and dolomitic rocks of the middle and upper Miocene Monterey Formation. For this assessment, the play also includes lower and middle Miocene sandstones in the Point Sal and Lospe Formations. The play encompasses an area of approximately 3,800 square miles and occurs at burial depths of approximately 0 (seafloor) to 11,000 feet (fig. 60).

Petroleum Geologic Characteristics

The Monterey Formation is its own source and reservoir rock. Using surface samples from the Santa Barbara coastal area and core samples from the onshore Santa Maria basin, Isaacs (1984) calculated an average total organic carbon (TOC) content of approximately 5 percent; maximum TOC values are as high as 17 percent. Crain and others (1985) report average TOC values of 3 percent in the Point Arguello field. Other geochemical data (i.e., hydrogen-carbon and oxygen-carbon ratios) from the Santa Barbara coast and Pismo basin indicate that organic matter in the Monterey Formation contains type II kerogen (Isaacs and others, 1983). Oil gravities from offshore drill-stem tests range from less than 5 to 35 ^{o}API (the median value is 14 ^{o}API). The source for petroleum in the Point Sal Formation is also the Monterey Formation.

Reservoir rocks in this play include fractured siliceous and dolomitic rocks of the Monterey Formation, as well as sandstones in the Point Sal and Lospe Formations. Reservoir quality in the Monterey Formation ranges from poor to excellent, depending on the diagenetic grade of the siliceous strata. Many researchers believe that the best potential Monterey reservoir rocks are those in which the siliceous strata have been diagenetically altered from opal-CT to quartz, due to the increased fracture density associated with quartz-phase strata (see Central California province discussion). Mineralogic analyses of well samples from six wells in the offshore Santa Maria basin indicate that diagenetic alteration of opal-CT to quartz has occurred in all of the analyzed wells. Further, the stratigraphic position of this diagenetic boundary has been correlated with an anomalous, often cross-cutting seismic reflector that can be traced throughout much of the offshore Santa Maria basin. On the Piedras Blancas antiform in northern Santa Maria basin, the diagenetic reflector is absent, possibly because burial has been insufficient to convert opal-CT to quartz. The absence of the diagenetic reflector in the Partington basin may be attributed to other factors because the depth of burial appears sufficient to have converted opal-CT to quartz. Migration of fluids into the Monterey structures occurs along fractures and faults, some of which cross the diagenetic boundary. Migration into structures in the Point Sal and Lospe Formations may generally occur where sandstones in these formations lie in updip contact with Monterey source rocks.

Traps in the drilled areas of the offshore Santa Maria basin are primarily structural and generally occur in faulted and/or fault-bounded anticlines. The Hosgri, Purisima, and Lompoc fault zones bound the eastern offshore Santa Maria basin and trend northwest from near Point Arguello to approximately 10 miles north of Point Sal. The Hosgri fault zone continues northward through the Partington basin. Many of the fields discovered in the central offshore Santa Maria basin are related to the faulting associated with these zones. In the undrilled areas of the basins, traps have been identified along the northern extension of the Hosgri fault zone and along uplifts and faulted uplifts in the middle and western parts of the southern and central offshore Santa Maria basin. Subthrust traps may exist along the Hosgri fault zone in the northern offshore Santa Maria basin and in Partington basin. Stratigraphic traps have been identified in the west-central and northwest part of the offshore Santa Maria basin and the southwest part of the Partington basin where the Monterey has been eroded on the crests of basement highs but may be trapped below capping mudstones of the Sisquoc Formation on the flanks of the uplifts. Traps are noticeably sparse in the Partington basin due to the lack of structural disruption. The Point Sal Formation was not mapped for this assessment but is expected to have similar trap styles as the Monterey Formation. Seals are generally provided by capping mudstones of the Sisquoc Formation or by faults, fractures, and unconformities. The diagenetic boundary between opal-CT and quartz may also trap petroleum on the flanks of anticlines and homoclines. Traps identified atop the Piedras Blancas antiform may lack the requisite overburden to provide an effective seal.

EXPLORATION AND DISCOVERY STATUS

The Monterey Formation has been the primary exploration target in the offshore Santa Maria basin since the discovery well (OCS-P 0316 #1) at the Point Arguello field was drilled in 1980. Since that time, 12 additional fields have been discovered. The Monterey Formation is the primary reservoir in all of the fields. Field sizes range from approximately 2 MMbbl to 324 MMbbl of combined oil-equivalent resources.

Although the exploration success ratio in the offshore Santa Maria basin is relatively high, some dry holes have been drilled. One such well (OCS-P 0496 #1) was drilled on top of a large, northeast-trending uplift in the south-central portion of the basin where the Monterey section is very thin and may never have been buried sufficiently to convert opal-CT to quartz. Additionally, a large anticline that breaches the seafloor in the west-central portion of the basin was drilled and found to be dry; although the well (OCS-P 0411 #1) penetrated more than 2,000 feet of Monterey section, no hydrocarbons were encountered. Mineralogic analyses subsequently revealed that siliceous strata in the lower half of the Monterey section are in the quartz phase; the single drill-stem test in the well was performed in opal-CT strata located 200 to 400 feet above the diagenetic boundary.

RESOURCE ESTIMATES

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the discovery assessment method. Select data used to develop the resource estimates are shown in appendix C.

Pool-size data from 13 discovered fields in the offshore portion of the play were used to develop the pool-size distribution. The largest pool in the play is assumed to be the Point Arguello field (original recoverable reserves are estimated to be 324 MMbbl of combined oil-equivalent resources). The second-largest discovered pool is the Rocky Point field (original recoverable reserves are estimated to be 99 MMbbl of combined oil-equivalent resources). Based on the assumption that an undiscovered pool larger than Rocky Point may exist (through remapping and combination of two existing smaller fields, or a new field discovery), a gap in the lognormal pool-size distribution (between the Point Arguello and Rocky Point fields) for this play has been modeled. Additionally, to aid in estimating the total number of pools that may exist, the number of undiscovered pools with a mean pool size in excess of 10 MMbbl of combined oil-equivalent resources is estimated to be 20. The resulting estimated total number of pools is 90.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 687 MMbbl of oil and 629 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in 77 pools with sizes ranging from approximately 60 Mbbl to 200 MMbbl of combined oil-equivalent resources (fig. 66). The low, mean, and high estimates of resources in the play are listed in table 20.

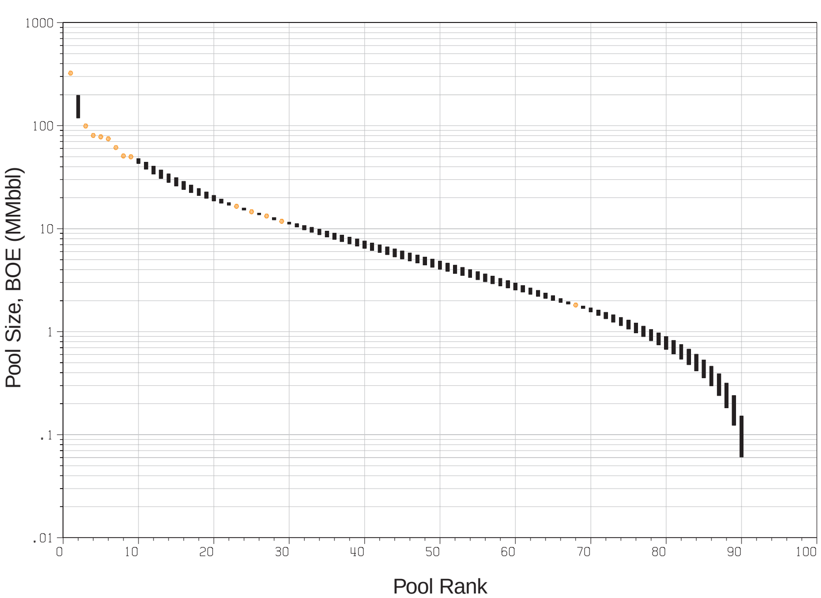

Figure 66. *Pool-size rank plot of estimated conventionally recoverable resources of the Monterey Fractured play, Santa Maria-Partington Basin assessment area. Sizes of discovered pools are shown by dots. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

Paleogene Sandstone Play

Play Definition

The Paleogene Sandstone play of the Santa Maria-Partington Basin assessment area is defined to include structural and stratigraphic accumulations of oil and associated gas in undifferentiated Paleogene clastic reservoirs. This play is conceptual because large volumes of Paleogene strata have not been previously identified in the Santa Maria or Partington basins[9]. Recent interpretation of seismic-reflection profiles indicates that a thick section of strata exists below the Monterey Formation in the western offshore Santa Maria basin and in the Partington basin. This seismic-stratigraphic unit appears as a narrow belt of strata lying unconformably below the Monterey Formation in the western offshore Santa Maria basin; the unit is bounded on the west by the Santa Lucia Bank fault and on the east by basement highs. It is traceable northwestward to the latitude of Morro Bay where it widens substantially and extends northward between flanking basement uplifts into the Partington basin. Between Point Estero and Cape San Martin, the unit narrows and extends northwestward along the Hosgri fault zone to about 12 miles northwest of Lopez Point. In Partington basin, the western limit of the play is defined solely by seismic character; over 10,000 feet of subparallel reflectors below the Monterey Formation terminate diffusely against chaotic basement reflectors, presumably of the Franciscan Complex. The play encompasses an area of approximately 500 square miles and occurs at burial depths generally greater than 8,000 feet (fig. 60).

Petroleum Geologic Characteristics

Potential petroleum source rocks for this play are estimated to be analogous to Paleogene source rocks in the Santa Barbara-Ventura basin (i.e., Anita and Cozy Dell Shales) and in the onshore La Honda basin. The Monterey Formation may be a secondary source where favorable migration conditions exist.

Potential reservoir rocks for this play are estimated to be analogous to Paleogene reservoirs in the Santa Barbara-Ventura basin and pre-Monterey sandstones in the Año Nuevo basin. The most probable sediment types are fine- to coarse-grained sandstones deposited in shelf and slope systems; however, the presence of deep-water turbidite sandstones cannot be discounted due to the great thickness (more than 10,000 feet) of deposits in the Partington basin.

No traps in this play have been mapped because the seismic data do not display much structural disruption within the seismic-stratigraphic unit that defines the play. Stratigraphic traps are the most likely trap type where the Paleogene strata abut basement highs in the western offshore Santa Maria basin and in the north-trending corridor from the Santa Maria basin to the Partington basin. In the Partington basin, where strata of this play abut the Hosgri fault zone, subthrust stratigraphic and structural traps may exist; however, individual traps are not identifiable on the seismic data. Seals may be provided by shales within this play, by siliceous rocks of the overlying Monterey Formation, and by faults and unconformities.

Exploration

No exploratory wells have penetrated this play. Thin sections of Paleogene strata have been reported in wells drilled in the southeastern part of the offshore Santa Maria basin; however, no hydrocarbon shows have been reported. The play is considered most prospective along the Hosgri fault zone where the section is thick and structural and stratigraphic traps may exist.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the Federal offshore portion of the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

The pool area was estimated by analogy to the Año Nuevo basin based on similar fault-bound basin margins. Net-pay thickness was estimated by analogy with Paleogene strata in the Año Nuevo and other offshore central California basins. The number of prospects was estimated by areal comparison to the Año Nuevo basin. The oil recovery factor (oil yield) and solution gas-to-oil ratio were

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[9] The existence of this play presumes that the strata identified using seismic data are of Paleogene age. The possibility exists that the strata are of Cretaceous age and, therefore, may be less prospective; this possibility has been considered in estimating the probability of success of the play. If the strata are of Cretaceous age, this finding may be important in determining the offset along the Hosgri fault zone, because Cretaceous strata crop out on the east side of the fault along the coast as far south as Cayucos Point. Further mapping is necessary to confirm this possibility; but, based on mapping for this project, right-lateral offset of approximately 30 miles is feasible.

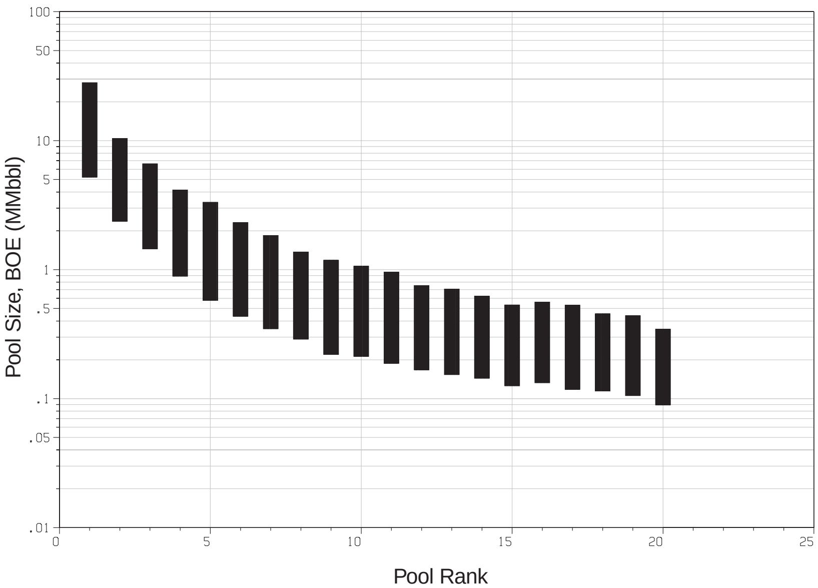

Figure 67. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Paleogene Sandstone play, Santa Maria-Partington Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*

estimated by analogy to Paleogene reservoirs in the Santa Barbara-Ventura basin. The probability of success of this play (play chance) is estimated to be poor (20 percent), primarily because of the uncertainty regarding the age and lithologic character of the strata. If the play exists, the dearth of structural traps and only suspected stratigraphic traps resulted in a predicted prospect success ratio (conditional prospect chance) of 20 percent.

As a result of this assessment, the Federal offshore portion of the play is estimated to contain 7 MMbbl of oil and 21 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 20 pools with sizes ranging from approximately 90 Mbbl to 30 MMbbl of combined oil-equivalent resources (fig. 67). The low, mean, and high estimates of resources in the play are listed in table 20.

BRECCIA PLAY

PLAY DEFINITION

The Breccia play of the Santa Maria-Partington Basin assessment area is defined to include stratigraphic and fault-trapped accumulations of oil and associated gas in brecciated basement rocks along the Santa Lucia Bank fault and other nearby basement highs (fig. 60). This play is conceptual because the breccia has not been drilled and is inferred to exist based solely on seismic-reflection data. The "breccia" seismic-stratigraphic unit appears as a narrow zone of disrupted reflectors that are confined to the hanging-wall block of the Santa Lucia Bank fault and basement highs immediately east of the fault. In the offshore Santa Maria basin, the Santa Lucia Bank fault juxtaposes Monterey and younger strata, and possibly Paleogene strata, against uplifted and eroded Franciscan basement. The zone of disruption exists along the entire trace of the fault. The existence of breccia on the eastern flanks of the basement highs is only postulated based on seismic evidence that Franciscan basement has been uplifted and eroded and is covered by a thin veneer of Pliocene(?) and younger strata. The play covers an area of approximately 275 square miles and occurs at burial depths from 500 to 2,500 feet (2,500 to 4,500 feet below sea level).

PETROLEUM GEOLOGIC CHARACTERISTICS

Potential source rocks for this play are organic-rich shales of the Monterey Formation where they are in contact with the breccia zone. The oil is likely to be low gravity and high in sulphur, similar to Monterey oils found in tests and production to the east.

Potential reservoir rocks for this play are brecciated basement rocks of the Franciscan Complex. Seismic profiles across the Santa Lucia Bank fault indicate that uplifted Franciscan basement in the foot-wall block to the west has been eroded and possibly redeposited eastward, forming a zone of chaotic reflectors that extend eastward away from the fault for distances up to 7,000 feet. Additionally, eroded basement highs immediately east of the fault at the latitude of Point Sal and Morro Bay may have shed detrital material in all directions. The reservoir quality of this play may vary; porosities of analogous breccias onshore range from 12 to 31 percent.

Stratigraphic traps may exist against basement highs east of the Santa Lucia Bank fault; but, seismic data indicate that fault traps are the predominant trap type in this play. No specific traps have been mapped using the seismic data; however, a zone where traps are likely to exist has been delineated. The potential for effective sealing against the Santa Lucia Bank fault is very uncertain because the fault may have been active since its inception in the early to middle Miocene.

Exploration

No exploratory wells have drilled this play in the offshore Santa Maria basin.

Resource Estimates

Undiscovered Conventionally Recoverable Resources

Estimates of undiscovered conventionally recoverable resources in the play have been developed using the subjective assessment method. Select data used to develop the resource estimates are shown in appendix C.

The pool area, net-pay thickness, number of prospects, and oil recovery factor (oil yield) of this play were estimated by comparison to the San Onofre Breccia play in the Los Angeles Basin assessment area. The solution gas-to-oil ratio was estimated to be identical to the ratio for the Monterey Fractured play in the Santa Maria-Partington Basin assessment area. The probability of success of the play (play chance) is estimated to be very poor (15 percent) because the existence of the breccia is postulated solely on the basis of seismic data. If the play exists, the uncertainty regarding the effectiveness of a seal along the Santa Lucia Bank fault resulted in a predicted prospect success ratio (conditional prospect chance) of 15 percent.

As a result of this assessment, the play is estimated to contain 8 MMbbl of oil and 8 Bcf of associated gas (mean estimates). This volume of undiscovered conventionally recoverable resources may exist in as many as 17 pools with sizes ranging from approximately 290 Mbbl to 35 MMbbl of combined oil-equivalent resources (fig. 68). The low, mean, and high estimates of resources in the play are listed in table 20.

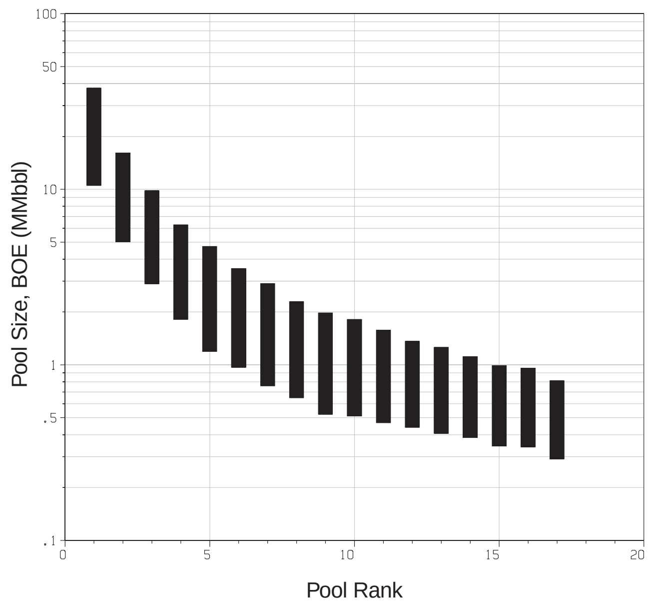

Figure 68. *Pool-size rank plot of estimated undiscovered conventionally recoverable resources of the Breccia play, Santa Maria-Partington Basin assessment area. Sizes of undiscovered pools are shown by bars; the top and bottom of a bar represent the 25th- and 75th-percentile values of a probability distribution, respectively.*